



February 12, 2009

Memorandum

To: Members of the Board

From: Julia E. Ranagan, Assistant Director

Through: Wendy M. Payne, Executive Director

Subj: Natural Resources – Tab F¹

OVERALL MEETING OBJECTIVE

The purpose of this 105 minute session is to reach consensus on the changes made [and not made] to the draft revised exposure draft (ED) on *Accounting for Federal Oil and Gas Resources* since the December 2008 board meeting so that staff can work towards a pre-ballot draft for the April 2009 board meeting.

BRIEFING MATERIAL

Attached to this transmittal memorandum, you will find a staff discussion paper on the changes made to the revised exposure draft since the December 2008 board meeting. In addition, the following materials are included in their respective tabs:

- Tab F-1 – Draft Revised ED, *Accounting for Federal Oil and Gas Resources*
- Tab F-2 – Appendix 1 – Issue Papers
- Tab F-3 – Appendix 2 – Recommended Response to Field Test Comments
- Tab F-4 – Appendix 3 – Natural Resources History of Project and Key Decisions

In an effort to cut down on the amount and cost of duplicate material that is provided for each meeting, the following materials that have been provided in the past will be available at the board table in an individual binder for each member (as was done at the October and December board meetings):

- Task Force Discussion Paper, *Accounting for the Natural Resources of the Federal Government*, issued June 2000
- ED, *Accounting for Federal Oil and Gas Resources*, issued May 2007

¹ The staff prepares Board meeting materials to facilitate discussion of issues at the Board meeting. This material is presented for discussion purposes only; it is not intended to reflect authoritative views of the FASAB or its staff. Official positions of the FASAB are determined only after extensive due process and deliberations.

- Comment Letters on ED
- Field Test Questionnaire Responses (in color to mark differences)
- Comparison of ED to Field Test Questionnaire Responses (in color to mark differences)

You may electronically access all of the briefing material at <http://www.fasab.gov/meeting.html>.

NEXT STEPS

April 2009 Meeting

- Provide additional information on the fiduciary reporting requirement, if provided, to enable the board to reach consensus on whether to retain the recognition requirements as an integral part of the fiduciary activities Schedules of Fiduciary Activity and Net Assets.
- Provide additional information on how to treat custodial reporting for other commodities to enable the board to reach consensus on how the other commodities should be addressed in the interim until standards on all natural resources are issued.
- Provide a pre-ballot revised exposure draft that incorporates decisions from the February 2009 meeting.
- Provide a ballot draft that incorporates final member comments via email after the meeting.

May 2009

- Issue a revised exposure draft with comments due by late July 2009.

August 2009 Meeting

- Discuss comments received on revised exposure draft.

October 2009 Meeting

- Finalize wording.
- Provide pre-ballot draft after meeting via email.

November 2009

- Provide ballot draft via email (will not be on December 2009 agenda if approved before meeting and there are no issues).
- Provide proposed standard to sponsors.

February 2010

- Issue final standard after sponsor review.

BACKGROUND

The original exposure draft (ED), *Accounting for Federal Oil and Gas Resources*, proposed accounting standards for federal oil and gas resources. The proposed standards would result in the recognition of an asset and a related liability. The asset would be referred to as “estimated petroleum royalties” and would present the royalty share of the federal oil and gas resources classified as “proved reserves.” The asset’s value would be calculated by multiplying the estimated quantity of proved oil and lease condensate, natural gas plant liquids (NGPLs), and gas reserves by the effective average royalty rate for each quantity and by the average per unit price for each quantity. An alternative approach to valuing estimated petroleum royalties is fair value. The CBO member believes that fair value is feasible and preferable. The CBO member’s alternative view proposed that fair value be derived from market transactions or discounted cash flows.

The related liability would be for the royalty share of the federal oil and gas resources classified as “proved reserves” designated to be distributed to others, e.g., state governments and – at the component entity level – other federal agencies and the general fund of the U.S. Treasury. The liability would be calculated by assessing the total estimated petroleum royalties to be distributed to others.

When oil and gas resources are extracted and royalties are earned, revenue and a depletion expense equal to the earned revenue would be recognized by the federal government. When revenue collections are distributed a reduction in the liability for revenue distributions to others would be recognized. Gains and losses due to changes in the estimated quantity of proved oil and lease condensate, NGPLs, and gas reserves, the effective regional average royalty rates, and the average per unit prices would be recognized based on an annual valuation of the asset with an associated adjustment to the liability for revenue distributions to others. In addition, when rights to a future royalty stream are identified to be sold, the value of the related rights would be disclosed.

Additional information about federal oil and gas resources not classified as proved reserves would be disclosed in notes to the financial statements or reported as required supplementary information (RSI). The proposed standards would be effective for periods beginning after September 30, 2009 (fiscal year 2010), with early implementation permitted.

Based on the results of field testing and comments received from respondents, the Board is proposing several significant changes to the ED which will require re-exposure.

See Tab F-4 for a timeline history of the project and key decisions since its original inception in May 1995.

If you require additional information or wish to suggest another alternative not considered in the staff paper, please contact me as soon as possible. Ideally, I would be able to respond to your request for information or develop more fully the alternative you wish considered in advance of the meeting. If you have any questions or comments prior to the meeting, please contact me by telephone at 202.512.7377 or by e-mail at ranaganj@fasab.gov.

Attachment

CHANGES MADE TO THE DECEMBER 2008 REVISED ED

The following changes were made to the December 2008 revised ED:

1. **Revised paragraph 27 [from the December 2008 revised draft ED] to remove explicit reference to the formula [price X quantity X rate] as requested by a majority of the board members at the December 2008 meeting.**

This change was made at the request of the majority of the board members at the December 2008 meeting that the formula be removed from paragraph 27 and the language be softened [requested by Messrs. Torregrosa, Steinberg, Farrell, Jackson, Schumacher, and Allen]. See paragraph 24 in the revised draft ED at Tab F-1 for the revised language.

2. **Deleted the proposed component entity RSI requirements in paragraphs 44a and 45 [from the December 2008 revised draft ED] and replaced them with requirements to present the major assumptions used to calculate the value of the federal government's estimated petroleum royalties, explain the changes in the estimate from one year to the next, and reference the source reports used.**

This change was made because the original requirements were not supported by respondents to the ED. Furthermore, EIA has not provided the information necessary for the preparer to be able to present such information. See paragraph 43 in the revised draft ED at Tab F-1 for the revised requirements and Issue Paper No. 1 in Appendix 1 at Tab F-2 for further information and staff analysis.

3. **Clarified that the liability for revenue distributions to others is a long-term liability and that the estimated portion of the liability to be distributed within 12 months of the fiscal year-end may be classified as current.**

This clarification was added at the request of DOI. See paragraphs 28 and 29 in the revised draft ED at Tab F-1 for the revised requirements and Issue Paper No. 3 in Appendix 1 at Tab F-2 for further information and staff analysis.

4. **Clarified paragraph 28 [from the December 2008 revised draft ED] to require that a change in methodology be accounted for as a change in accounting estimate effected by a change in accounting principle.**

This change was made to address Mr. Farrell's question of whether a change in methodology after the initial year of implementation should be treated as a change in principle rather than a change in estimate. Since changes in estimates are not explicitly addressed in FASAB standards,² staff adapted the guidance from SFAS 154, *Accounting Changes and Error Corrections (as amended)*, which defines a change in accounting estimate effected by a change in accounting principle as a change in accounting estimate that is inseparable from the effect of a related change in accounting principle. The financial statements of prior periods should not be restated for a change in accounting estimate. See paragraphs 24 – 26 and A44 through A47 in

² SFFAS 21, *Reporting Correction of Errors and Changes in Accounting Principles*, explicitly addresses corrections of errors and changes in principles. Indirect references to changes in estimate are made in SFFAC 5, footnote 10; SFFAS 6, pars. 99, 110, 190, and 191; Interpretation 4, par. 9; Technical Bulletin 2006-1, pars. 34 and 48; and Technical Release 2, par. 4.

the revised draft ED at Tab F-1 for the revised requirements and discussion in the Basis for Conclusions.

5. **Revised the liability recognition requirements in paragraphs 29 through 31 [from the December 2008 revised draft ED] so that only a liability for revenue to be distributed to non-federal entities (e.g., states) is required to be recognized.** A liability for revenue to be distributed to other federal entities is no longer required to be recognized. However, each federal receiving entity would disclose its relationship with the royalty revenue program and an estimate of the total amount of estimated petroleum royalties to be distributed to it in the notes to its financial statements.

This change was made based on the response to the field test questionnaire and a cost-benefit analysis. Staff believes that it is doubtful that the federal receiving entity management would find much decision-useful information with the recognition of a receivable that would be extremely volatile and could not be relied upon for short or long-term budget decisions. In addition, it is doubtful that the financial statement users would find more value in recognition of a receivable on the face of as opposed to in the notes to the financial statements. See paragraphs 27 – 30 and A55 through A59 in the revised draft ED at Tab F-1 for the revised requirements and discussion in the Basis for Conclusions, and Issue Paper No. 6 in Appendix 1 at Tab F-2 for further information and staff analysis.

6. **Incorporated detailed requirements for reporting on changes in long-term assumptions based on guidance in SFFAS 33.**

As promised in par. 41 of the December 2008 draft of the revised ED, staff explored the need for additional guidance on what would constitute a change in assumption for oil and gas vs. true gains and losses by reviewing the requirements of SFFAS 33 and discussing changes in oil and gas estimates with DOI personnel. See paragraphs 42f and 46 in the revised draft ED at Tab F-1 for the revised requirements and Issue Paper No. 5 in Appendix 1 at Tab F-2 for further information and staff analysis.

7. **Incorporated accounting and disclosure requirements for the federal receiving entities.**

This change was made because Mr. Steinberg and the field test team pointed out that the pro forma transactions included entries for the federal entities that receive royalty distributions but receiving entity accounting and reporting requirements were not addressed in the standard itself. As noted in number 5 above, staff has proposed to eliminate the proposed recognition of a liability for other federal entities that was contained in the May 2007 ED. However, staff has recommended that the federal receiving entity disclose its relationship with the royalty revenue program and an estimate of the total amount of estimated petroleum royalties to be distributed to it in the notes to its financial statements. Staff also proposes adding the required accounting by the federal entities when royalty distributions are received. See paragraphs 44 and 45 in the revised draft ED at Tab F-1 for the new requirements.

8. Reinstated the detailed pro forma transactions and detail on how values were derived.

This change was made based on comments received from the field test team and Mr. Steinberg, indicating that the pro forma transactions did not provide enough detail to be useful. See Appendix C in the revised draft ED at Tab F-1.

9. Incorporated several minor edits from the field test team.

See Tab F-3 for Appendix 2, Summary of May 2007 ED Requirements and Recommended Response to Field Test Comments. This appendix includes a summary of the May 2007 ED requirements and the field test team's comments to both the ED and PV views along with a recommended response from staff.

10. Incorporated board member comments on the December 2008 revised draft ED.

Various editorial and other changes were made to incorporate comments on the December 2008 revised draft ED received from Messrs. Steinberg, Patton, and Farrell.

11. Updated the basis for conclusions accordingly.

CHANGES NOT MADE TO THE DECEMBER 2008 REVISED ED

The following requested changes were ***not*** made to the December 2008 revised ED:

12. Recognition of depletion expense in an amount equal to royalty revenue has not been changed. For a number of reasons, the DOI field test team requested depletion be recorded based upon royalty reporting lines received and accepted for the preceding 12 sales months available at fiscal year end (July through June). FASAB staff believes that the depletion approach in the ED was not devised to show the "true" effect on the asset during the period since the quantity gets adjusted again at year-end as part of the revaluation. Rather, the depletion approach was an attempt to ensure that the only bottom line effect on MMS' statement of net cost was the net gain / loss that resulted from quantity and value differences from one year to the next. In other words, the depletion approach in the ED is to "match" depletion expense with revenue recognition. Therefore, FASAB staff recommends retaining the current requirements related to depletion expense. See Issue Paper No. 4 in Appendix 1 at Tab F-2 for further information and staff analysis.

13. Recognition of gain / loss on the component entity's statement of net cost has not been changed. At the December 2008 board meeting, Mr. Jackson stated that he thinks it is inappropriate for the gains and losses on revaluation to show up on DOI's financial statements. He sees where the gains and losses recognized on the statement of net cost are offset by a transfer out on the statement of changes in net position, but he does not believe that the agency should be saddled with reporting those gains and losses since they are not true gains and losses for DOI. Based on staff's understanding of Statement of Federal Financial Accounting Concepts 5, *Definition of Elements and Basic Recognitions Criteria for Accrual-Basis Financial Statements*, and the intent of the board when developing that statement, staff believes it is appropriate for the gains and losses from revaluation of estimated petroleum

royalties to be reported in the statement of net cost of DOI because they are the component entity most closely responsible for managing royalty revenue. Therefore, FASAB staff recommends retaining the requirement that gains and losses from revaluation of estimated petroleum royalties be reported in the statement of net cost of DOI. See Issue Paper No. 6 in Appendix 1 at Tab F-2 for further information and staff analysis.

ISSUES NOT YET ADDRESSED

The following open issues from the December 2008 meeting still need to be addressed by staff and presented for board member consideration:

- 14. Fiduciary disclosure requirements have not been addressed.** Staff has not received a response from DOI to enable the board to make an informed decision regarding cost/benefit. See Issue Paper No. 2 in Appendix 1 at Tab F-2 for further information and staff analysis. Staff proposes no changes to the current requirements at this time and will continue to seek a response to this issue.

- 15. Accounting for other commodities has not been addressed.** Staff will address this issue at the April 2009 board meeting.

QUESTION FOR THE BOARD MEMBERS

Do you object to any of the changes made [or not made] to the revised draft ED? If so, please explain the reasons for your objection and offer alternative solutions.

Tab F-1
Draft Revised ED,
Accounting for Federal
Oil and Gas Resources

[This page intentionally left blank.]



Federal Accounting Standards Advisory Board

**Accounting for
Federal Oil and Gas Resources**

Statement of Federal Financial Accounting Standards

Revised Exposure Draft

Written comments are requested by [date 60 days after issuance]

[Month day, year]

Working Draft – Comments from Respondents Are Not Requested on This Draft

THE FEDERAL ACCOUNTING STANDARDS ADVISORY BOARD

The Secretary of the Treasury, the Director of the Office of Management and Budget (OMB), and the Comptroller General, established the Federal Accounting Standards Advisory Board (FASAB or "the Board") in October 1990. FASAB is responsible for promulgating accounting standards for the United States Government. These standards are recognized as generally accepted accounting principles (GAAP) for the Federal Government.

An accounting standard is typically formulated initially as a proposal after considering the financial and budgetary information needs of citizens (including the news media, state and local legislators, analysts from private firms, academe, and elsewhere), Congress, Federal executives, Federal program managers, and other users of Federal financial information. The proposed standards are published in an Exposure Draft for public comment. In some cases, a discussion memorandum, invitation for comment, or preliminary views document may be published before an exposure draft is published on a specific topic. A public hearing is sometimes held to receive oral comments in addition to written comments. The Board considers comments and decides whether to adopt the proposed standard with or without modification. After review by the three officials who sponsor FASAB, the Board publishes adopted standards in a Statement of Federal Financial Accounting Standards. The Board follows a similar process for Statements of Federal Financial Accounting Concepts, which guide the Board in developing accounting standards and formulating the framework for Federal accounting and reporting.

Additional background information is available from the FASAB or its website:

- "Memorandum of Understanding among the General Accounting Office, the Department of the Treasury, and the Office of Management and Budget, on Federal Government Accounting Standards and a Federal Accounting Standards Advisory Board."
- "Mission Statement: Federal Accounting Standards Advisory Board", Exposure drafts, Statements of Federal Financial Accounting Standards and Concepts, FASAB newsletters, and other items of interest are posted on FASAB's website at: www.fasab.gov.

Federal Accounting Standards Advisory Board

441 G Street, NW, Suite 6814

Mail stop 6K17V

Washington, DC 20548

Telephone 202-512-7350

FAX – 202-512-7366

www.fasab.gov

This is a work of the U. S. government and is not subject to copyright protection in the United States. It may be reproduced and distributed in its entirety without further permission from FASAB. However, because this work may contain copyrighted images or other material, permission from the copyright holder may be necessary if you wish to reproduce this material separately.



1 **ISSUE DATE**

2 TO: ALL WHO USE, PREPARE, AND AUDIT FEDERAL FINANCIAL INFORMATION

3 The Federal Accounting Standards Advisory Board (FASAB or the Board) is requesting
4 comments on the revised exposure draft of a proposed Statement of Federal Financial
5 Accounting Standards entitled, *Accounting for Federal Oil and Gas Resources*.
6 Substantive changes have been made to the original exposure draft issued on May 21,
7 2007.

8 Specific questions for your consideration [begin](#) on page 1 but you are welcome to
9 comment on any aspect of this proposal. If you do not agree with the proposed
10 approach, your response would be more helpful to the Board if you explain the reasons
11 for your position and any alternative you propose. Responses are requested by **DUE**
12 **DATE**.

Deleted: appear

13 All comments received by the FASAB are considered public information. Those
14 comments may be posted to the FASAB's website and will be included in the project's
15 public record.

16 We have experienced delays in mail delivery due to increased screening procedures.
17 Therefore, please provide your comments in electronic form. Responses in electronic
18 form should be sent by e-mail to fasab@fasab.gov. If you are unable to provide
19 electronic delivery, we urge you to fax the comments to (202) 512-7366. Please follow
20 up by mailing your comments to:

21 Wendy M. Payne, Executive Director
22 Federal Accounting Standards Advisory Board
23 Mailstop 6K17V
24 441 G Street, NW, Suite 6814
25 Washington, DC 20548

26 The Board's rules of procedure provide that it may hold one or more public hearings on
27 any exposure draft. No hearing has yet been scheduled for this exposure draft. Notice
28 of the date and location of any public hearing on this document will be published in the
29 *Federal Register* and in the FASAB's newsletter.

30

31 Tom L. Allen
32 Chairman

[This page intentionally left blank.]

1 Executive Summary

2 What is the Board proposing?

3 This exposure draft (ED) proposes accounting standards for federal oil and gas
 4 resources.¹ The proposed standards would result in the recognition of an asset and a
 5 liability. The asset would be referred to as “estimated petroleum royalties.” The asset’s
 6 value would be the royalty share of the federal oil and gas resources classified as
 7 “proved reserves.”² The liability would be for the royalty share of the federal proved
 8 reserves designated to be distributed to non-federal entities, e.g., state governments,³

Deleted: others

Deleted: i.e

Deleted: and – at the component entity level – other federal agencies and the general fund of the U.S. Treasury

9 When oil and gas resources are extracted and royalties are earned, revenue and a
 10 depletion expense equal to the earned revenue would be recognized by the federal
 11 government. When revenue collections are distributed, a transfer out for revenue
 12 distributions to federal entities and a reduction in the liability for revenue distributions to
 13 non-federal entities would be recognized. Gains and losses would be recognized based
 14 on an annual valuation of the asset with an adjustment to the liability for revenue
 15 distributions to non-federal entities. In addition, when rights to a future royalty stream
 16 are identified to be sold, the value of the related rights would be disclosed.

Deleted: others

Deleted: others

17 Transition to these proposed standards would require that the federal government’s
 18 royalty share of oil and gas proved reserves be recognized as an asset as of the
 19 beginning of the reporting period in which the standards become effective. In addition,
 20 a liability for the portion that will be distributed to non-federal entities would be
 21 established at the same time. The net effect of recognizing an asset and establishing a
 22 liability for revenue distributions to non-federal entities at the beginning of the reporting
 23 period would be a change in accounting principle that increases the entity’s net position.

Deleted: others

Deleted: Additional information about federal oil and gas resources not classified as proved reserves would be disclosed in notes to the financial statements or reported as required supplementary information (RSI).

24 The proposed standards would be effective as RSI for periods beginning after September
 25 30, 2010, and as basic information for periods beginning after September 30, 2013,
 26 except where specifically designated as required supplementary information (RSI).
 27 Earlier implementation is encouraged.

¹ Federal Oil and Gas Resources: Oil and gas resources over which the federal government may exercise sovereign rights with respect to exploration and exploitation and from which the federal government has the authority to derive revenues for its use. Federal oil and gas resources do not include resources over which the federal government acts as a fiduciary for the benefit of a non-federal party.

² A portion of the production value of proved oil and gas reserves are due to the federal government from the lessee in accordance with the royalty rate contained in the lease agreement.

³ Upon collection, the majority of the federal government’s estimated petroleum royalties from the production of federal oil and gas proved reserves are distributed to state governments, other federal agencies, and the general fund of the U.S. Treasury in accordance with legislated allocation formulas.

Deleted: states

1 **How would this proposal improve federal financial reporting and contribute to**
 2 **meeting the federal financial reporting objectives?**

3 The federal government is accountable to the American citizens for proper stewardship
 4 of federal assets. Federal oil and gas resources represent federal assets. Accounting
 5 for and reporting information about these assets would enhance:

- 6 a. accountability for and stewardship over assets of the federal government;
 7 b. consistency and understandability in accounting for assets of the federal
 8 government; and,
 9 c. relevance, consistency, and comparability of information regarding revenue of
 10 the federal government.

11
 12 Recognizing the federal government's royalty share of proved reserves as an asset on
 13 the balance sheet would provide transparency regarding the value and changes in value
 14 of these significant assets. Federal financial reports would be more relevant, consistent,
 15 and complete. The effect of some legislative changes related to oil and gas resources
 16 would be communicated to the taxpayers in the period that the changes are made.
 17 Additional disclosures about federal oil and gas resources would provide
 18 comprehensive information about federal assets, reveal changes in the quantity and
 19 status of oil and gas resources, and make quantity information more accessible to users
 20 of financial information.

21 Bonus bid, rent, and royalty
 22 collections – currently treated as
 23 nonexchange revenue due to the
 24 absence of cost information – would
 25 be accounted for and reported in
 26 accordance with exchange revenue
 27 standards. This treatment would
 28 improve the comparability of revenue
 29 information.

30 Of the four objectives outlined in
 31 Statement of Federal Financial
 32 Accounting Concepts Statement
 33 (SFFAC) 1, *Objectives of Federal*
 34 *Financial Reporting*, the operating
 35 performance and stewardship
 36 objectives were identified as most
 37 important for natural resources
 38 reporting.
 39

Operating Performance Objective

Federal financial reporting should assist report users in evaluating the service efforts, costs, and accomplishments of the reporting entity; the manner in which these efforts and accomplishments have been financed; and the management of the entity's assets and liabilities. Federal financial reporting should provide information that helps the reader to determine

- the costs of providing specific programs and activities and the composition of, and changes in, these costs;
- the efforts and accomplishments associated with federal programs and the changes over time and in relation to costs; and
- the efficiency and effectiveness of the government's management of its assets and liabilities.

Source: SFFAC 1

1 With respect to meeting the operating performance reporting objective, the proposed
 2 standards would provide information useful in evaluating the reporting entity's
 3 management of assets relating to oil and gas resources. This information would allow
 4 financial report users to monitor changes in royalty rates and estimated reserve
 5 quantities, providing an indicator of how well the government's proved reserves were
 6 managed. In addition, the value of the estimated petroleum royalties at the end of each
 7 period would facilitate consideration of the potential cash flows from existing leases.

8
 9 Currently, royalties from oil and gas leases are displayed on the statement of changes
 10 in net position with non-exchange revenue rather than on the statement of net cost with
 11 other exchange revenue. Presentation of revenues arising from oil and gas leasing
 12 activities as exchange revenue would assist users in understanding how the
 13 government's efforts and
 14 accomplishments were financed. The
 15 current practice of combining
 16 revenues derived from the sale of
 17 assets with revenues derived from
 18 taxation or other non-exchange
 19 sources may obscure the fact that
 20 ~~costs were incurred to generate the~~
 21 ~~revenues—the federal government~~
 22 ~~exchanged~~ proved reserves for a
 23 future stream of royalty payments.

Stewardship Objective
Federal financial reporting should assist report users in assessing the impact on the country of the government's operations and investments for the period and how, as a result, the government's and the nation's financial condition has changed and may change in the future. Federal financial reporting should provide information that helps the reader to determine whether <ul style="list-style-type: none"> – the government's financial position improved or deteriorated over the period, – future budgetary resources will likely be sufficient to sustain public services and to meet obligations as they come due, and – government operations have contributed to the nation's current and future well-being.
Source: SFFAC 1

Deleted: the gains were obtained through the exchange of resources

Comment: From H. Steinberg: What the reader gets from the changes proposed by this standard is an understanding of the costs incurred to generate the revenue. A better argument might be that the current practice obscures the fact that costs were incurred to generate the revenues.

24 With respect to meeting the
 25 stewardship reporting objective, the
 26 proposed standards would provide
 27 information useful in assessing
 28 whether federal government
 29 operations have contributed to the
 30 nation's current and future well-being.

31 Recognition of estimated petroleum royalties as an asset would make available the
 32 value of an asset that generates cash to finance government operations over time. This
 33 would inform users about the financial position of the government and whether it was
 34 improving or deteriorating over time. Information about potential oil and gas production
 35 and changes in potential production over time would allow users to consider how
 36 government operations and economic conditions have impacted the availability of oil
 37 and gas resources to future generations.

[This page intentionally left blank.]

Table of Contents

Executive Summary	i
What is the Board proposing?	i
How would this proposal improve federal financial reporting and contribute to meeting the federal financial reporting objectives?.....	ii
Questions for Respondents	1
Introduction	3
Purpose	3
Materiality	3
Estimation Methodology	4
Effective Date	4
Proposed Standards.....	5
Scope	5
Definitions.....	5
Asset Recognition.....	6
Liability Recognition.....	8
Revenue and Expense Recognition.....	9
Future Royalty Rights Identified for Sale	10
Annual Valuation of Estimated Petroleum Royalties.....	11
Disclosures and Required Supplementary Information.....	12
Component Entity Disclosures	12
Component Entity Required Supplementary Information (RSI).....	14
Federal Receiving Entity Accounting and Reporting.....	14
Consolidated Financial Report (CFR) of the United States Government Disclosures	15

Disclosure Requirements for Fiduciary Oil and Gas Resources	15
Effect on Existing Standards.....	16
Effective Date	17
Appendix A: Basis for Conclusions	18
Project History	18
Overview of Federal Oil and Gas Resources.....	19
Conceptual Aspects of Federal Oil and Gas Resources as an Asset for Estimated Petroleum Royalties and a Liability for the Portion of Revenue to be Distributed to Non-Federal Entities	23
Recognition Criteria.....	23
Asset Recognition	24
Liability Recognition	29
Reporting the Gains and Losses from Changes in Assumptions and Selecting Discount Rates	31
Future Rights to Royalty Streams Identified for Sale	32
Disclosures	33
Original Exposure Draft	33
Significant Changes Made to the Original Exposure Draft.....	38
Appendix B: Illustration of the Components of Federal Oil and Gas Resources	41
Appendix C: Pro Forma Transactions and Financial Statements	43
Appendix D: Abbreviations	55
Appendix E: Glossary.....	57

1 Questions for Respondents

2 The FASAB encourages you to become familiar with all proposals in the Statement
3 before responding to the questions in this section. In addition to the questions below,
4 the Board also would welcome your comments on other aspects of the proposed
5 Statement.

6 The Board believes that this proposal would improve federal financial reporting and
7 contribute to meeting the federal financial reporting objectives. The Board has
8 considered the perceived costs associated with this proposal. In responding, please
9 consider the expected benefits and perceived costs and communicate any concerns
10 that you may have in regard to implementing this proposal.

Deleted: Federal

Deleted: Federal

11 Because the proposals may be modified before a final Statement is issued, it is
12 important that you comment on proposals that you favor as well as any that you do not
13 favor. Comments that include the reasons for your views will be especially appreciated.

14 The questions in this section are available in a Word file for your use at
15 www.fasab.gov/exposure.html. Your responses should be sent by e-mail to
16 fasab@fasab.gov. If you are unable to respond electronically, please fax your
17 responses to (202) 512-7366 and follow up by mailing your responses to:

18 Wendy M. Payne, Executive Director
19 Federal Accounting Standards Advisory Board
20 Mailstop 6K17V
21 441 G Street, NW, Suite 6814
22 Washington, DC 20548

23 All responses are requested by [insert date].

24 Q1. The original exposure draft (ED) issued on May 21, 2007, contained detailed
25 asset valuation implementation guidance for valuing oil and gas resources. As
26 a result of feedback received from field testing efforts, the Board has removed
27 that detailed guidance from this revised ED and is instead proposing to provide
28 federal entities with flexibility in developing the asset valuation estimation
29 methodology due to the constantly changing economic and technical
30 conditions. Do you agree or disagree with the Board's position (see
31 paragraphs 19 through 23 and A42)? Please explain the reasons for your
32 position in as much detail as possible.

Deleted: Based on

Deleted: T

Comment: Based on comment from Hal Steinberg.

Deleted: for valuing oil and gas resources

Deleted: The detailed asset valuation implementation guidance contained in the original exposure draft (ED) issued on May 21, 2007, has been removed from this revised ED.

33 Q2. The Board believes that the method for valuing the federal government's
34 estimated petroleum royalties should approximate the present value of future
35 federal royalty receipts on proved reserves known to exist as of the reporting
36 date. Do you agree or disagree with the Board's position (see paragraphs 20

- 1 and A36 through A41)? Please explain the reasons for your position in as
2 much detail as possible.
- 3 Q3. The Board is proposing to permit alternative measurement methods for valuing
4 the federal government's estimated petroleum royalties if it is not reasonably
5 possible to estimate the present value of future federal royalty receipts on
6 proved reserves. Do you agree or disagree with the Board's position (see
7 paragraph 24)? Please explain the reasons for your position in as much detail
8 as possible.
- 9 Q4. The Board is proposing to permit federal entities to change its methodology for
10 valuing the federal government's estimated petroleum royalties if
11 environmental or other changes would provide for the development of an
12 improved methodology. Do you agree or disagree with the Board's position
13 (see paragraphs 25, 26 and A44 through A47)? Please explain the reasons for
14 your position in as much detail as possible.
- 15 Q5. The Board believes that it would be appropriate to apply the guidance
16 regarding reporting gains and losses from changes in assumptions and
17 selecting the discount rates from SFFAS 33, *Pensions, Other Retirement*
18 *Benefits, and Other Postemployment Benefits: Reporting the Gains and Losses*
19 *from Changes in Assumptions and Selecting Discount Rates and Valuation*
20 *Dates*, to long-term assumptions about oil and gas when using the present
21 value method. Do you agree or disagree with the Board's position (see
22 paragraphs 21, 40, and A60 through A62)? Please explain the reasons for your
23 position in as much detail as possible.
- 24 Q6. The Board is proposing to provide a three-year phase-in of the proposed
25 requirements from required supplementary information (RSI) beginning with
26 fiscal year 2011 to basic in fiscal year 2014. This transitional period is being
27 provided to allow for the asset valuation methodology to be improved upon
28 before an audit opinion is required. Do you agree or disagree with the Board's
29 position (see paragraphs 51 and A83)? Please explain the reasons for your
30 position in as much detail as possible.

1 Introduction

2 Purpose

- 3 1. Statements of Federal Financial Accounting Standards (SFFAS) 6,
4 *Accounting for Property, Plant, and Equipment*; 8, *Supplementary*
5 *Stewardship Reporting*; and 29, *Heritage Assets and Stewardship Land*,
6 establish standards related to federal lands, but specifically exclude natural
7 resources from the scope of those standards. Extensive federal oil and gas
8 resources exist on public lands throughout the country and on the Outer
9 Continental Shelf (OCS). Currently, federal financial reporting does not
10 provide information about the quantity or value of these assets. In addition,
11 royalty revenues are recognized but expenses are not recognized for the
12 asset exchanged to produce those revenues.
- 13 2. The Board believes that federal oil and gas resources represent federal
14 assets and accounting for and reporting information about these assets
15 would enhance:
 - 16 a. accountability for and stewardship over assets of the federal
17 government;
 - 18 b. consistency and understandability in accounting for assets of the
19 federal government; and,
 - 20 c. relevance, consistency, and comparability of information regarding
21 revenue of the federal government.
- 22 3. This Statement provides for a more complete accounting for oil and gas
23 resources available to the federal government. Recognizing the federal
24 government's royalty share of proved reserves as an asset on the balance
25 sheet would provide transparency regarding the value and changes in value
26 of these significant assets and result in information that contributes to
27 meeting federal financial reporting objectives.

Deleted: s

28 Materiality

- 29 4. The provisions of this Statement need not be applied to immaterial items.
30 The determination of whether an item is material depends on the degree to
31 which omitting or misstating information about the item makes it probable
32 that the judgment of a reasonable person relying on the information would
33 have been changed or influenced by the omission or the misstatement.

1 **Estimation Methodology**

- 2 5. The Board believes that the detailed estimation methodology for valuing oil
3 and gas natural resources should be developed by federal entities rather
4 than centrally by the Board. In an environment heavily affected by changes
5 in prices, technological advancements, economic and operating conditions,
6 and known geological, engineering, and economic data, estimation
7 methodologies may need to be regularly updated to reflect changing
8 economic and technological conditions.

9 **Effective Date**

- 10 6. The proposed standards are effective as RSI for periods beginning after
11 September 30, 2010, and as basic information for periods beginning after
12 September 30, 2013, except where specifically designated as RSI. Earlier
13 implementation is encouraged.

1 | **Proposed Standards**2 | **Scope**

- 3 | 7. This Statement applies to federal entities that report information about
 4 | federal oil and gas resources in general purpose financial reports prepared
 5 | in conformance with Federal Accounting Standards Advisory Board
 6 | (FASAB) standards.
- 7 | 8. This Statement articulates a general principle that should guide preparers of
 8 | general purpose federal financial reports in accounting for federal oil and
 9 | gas resources.
- 10 | 9. The concepts of an asset and a liability contained in this document are
 11 | consistent with those established in Statement of Federal Financial
 12 | Accounting Concepts (SFFAC) 5, *Definitions of Elements and Basic*
 13 | *Recognition Criteria for Accrual-Basis Financial Statements*. This
 14 | Statement establishes accounting for assets and liabilities related to federal
 15 | oil and gas resources that are not addressed by prior standards.
- 16 | 10. This Statement also amends SFFAS 7, *Accounting for Revenue and Other*
 17 | *Financing Sources*, to account for and report bonus bid, rent, and royalty
 18 | collections – currently treated as nonexchange revenue due to the absence
 19 | of cost information – in accordance with exchange revenue standards.

Comment: From H. Steinberg

Deleted: exclusively

20 | **Definitions**

- 21 | 11. Definitions in paragraphs 12 **and** 13 are presented first in the proposed
 22 | accounting standards because of their uniqueness in calculating the asset
 23 | value of estimated petroleum royalties. Other terms shown in **boldface**
 24 | **type** the first time they appear in this document are presented in the
 25 | Glossary (see page 57). Reviewers of this document may want to examine
 26 | all definitions before reviewing the proposed accounting standards and
 27 | Basis for Conclusions.
- 28 | 12. **Federal Oil and Gas Resources:** Oil and gas resources over which the
 29 | federal government may exercise sovereign rights with respect to
 30 | exploration and exploitation and from which the federal government has the
 31 | authority to derive revenues for its use. Federal oil and gas resources do
 32 | not include resources over which the federal government acts as a fiduciary
 33 | for the benefit of a non-federal party.

Deleted: through

Deleted: 56

1 | **13. Regional Estimated Petroleum Royalties:** Regional estimated petroleum
 2 | royalties means the estimated end-of-period value of the federal
 3 | government’s royalty share of proved oil and gas reserves from federal oil
 4 | and gas resources in each region.

5 | **Asset Recognition**

6 | **14.** Extensive federal oil and gas resources exist on public lands throughout the
 7 | country and on the **Outer Continental Shelf (OCS)**. These resources will
 8 | provide economic benefits to the federal government through revenue from
 9 | leasing activities and the collection of royalties on production. The federal
 10 | government controls access to these resources.

11 | **15.** Federal oil and gas resources are made up of two primary components –
 12 | discovered resources and undiscovered resources. Discovered and
 13 | undiscovered resources can be further defined as either proved reserves,
 14 | technically recoverable resources, or nonrecoverable resources. See
 15 | Appendix B: Illustration of the Components of Federal Oil and Gas
 16 | Resources on page 41 for an illustration of the universe of federal oil and
 17 | gas resources and a further breakdown of its components.

18 | **16.** Information is available in varying degrees and with varying reliability for
 19 | each component. While all of the federal oil and gas resources meet the
 20 | definition of an asset, the Board does not believe that the information for
 21 | other than proved reserves is sufficiently reliable to be recognized.

22 | **17.** The federal government’s estimated petroleum royalties from the production
 23 | of federal oil and gas proved reserves should be recognized as an asset on
 24 | the balance sheet of the component entity that is responsible for collecting
 25 | royalties. The value of the federal government’s estimated petroleum
 26 | royalties should be computed based on the calculation of federal oil and gas
 27 | proved reserves on a regional basis.

28 | **18.** For purposes of these standards, the regions used in determining and
 29 | reporting regional amounts or factors should be collaboratively developed
 30 | by all the component entities involved in oil and gas resource activities.
 31 | Regions used in calculating Regional Estimated Petroleum Royalties and in
 32 | applying these standards should be consistent and aligned with regions
 33 | used internally by the component entities in administering federal oil and
 34 | gas resource activities.

Deleted: ~~Regional Average First Purchase Price for Oil:~~ The regional average first purchase price for oil is calculated by dividing the total regional sales value of oil produced from federal oil and gas resources in each associated region for the preceding twelve (12) months by the total regional sales volume of oil produced from federal oil and gas resources in each associated region for the preceding twelve (12) months. All types of crude oil streams and gravity bands are aggregated for this calculation. ¶
~~Regional Average Wellhead Price for Gas:~~ The regional average wellhead price for gas is calculated by dividing the total regional sales value of gas produced from federal oil and gas resources in each associated region for the preceding twelve (12) months by the total regional sales volume of gas produced from federal oil and gas resources in each associated region for the preceding twelve (12) months. ¶
~~Effective Regional Average Royalty Rate:~~ The effective regional average royalty rate is calculated by dividing the royalty value (royalties) earned on the oil and gas proved reserves produced for each associated region for the preceding twelve (12) months by the total sales value of that production for the preceding twelve (12) months. ¶

- Formatted:** Bullets and Numbering
- Formatted:** Bullets and Numbering
- Deleted:** three different components –
- Deleted:** and
- Deleted:** undiscovered
- Deleted:** shall
- Deleted:** shall
- Deleted:** this
- Deleted:** shall
- Deleted:** this
- Deleted:** shall

- 1 | 19. The Board believes that the detailed estimation methodology for valuing oil
2 | and gas natural resources should be developed by federal entities rather
3 | than centrally by the Board.⁴ In an environment heavily affected by changes
4 | in prices, technological advancements, economic and operating conditions,
5 | and known geological, engineering, and economic data, estimation
6 | methodologies may need to be regularly updated to reflect changing
7 | economic and technological conditions.
- 8 | 20. The estimates that are developed should approximate the **present value** of
9 | future federal royalty receipts on proved reserves known to exist as of the
10 | reporting date. The estimates should be based on the best information
11 | available at fiscal year-end, or as close to the fiscal year-end as possible.
- 12 | 21. Discount rates as of the reporting date for present value measurements of
13 | oil and gas assets and liabilities should be based on interest rates on
14 | **marketable Treasury securities** with maturities consistent with the cash
15 | flows being discounted as required for pension, other retirement benefits
16 | (ORB) and other postemployment benefits (OPEB) in SFFAS 33, *Pensions,*
17 | *Other Retirement Benefits, and Other Postemployment Benefits: Reporting*
18 | *the Gains and Losses from Changes in Assumptions and Selecting*
19 | *Discount Rates and Valuation Dates.*⁵
- 20 | 22. The entity's estimates should reflect its judgment about the outcome of
21 | events based on past experience and expectations about the future.
22 | Estimates should reflect what is reasonable to assume under the
23 | circumstances. The entity's own assumptions about future cash flows may
24 | be used. However, the entity should review assumptions used generally in
25 | the federal government as evidenced by sources independent of the
26 | reporting entity, for example, those used by the Bureau of Economic
27 | Analysis for the National Income and Product Accounts and, if its
28 | assumptions do not reflect such data, an explanation of why it is
29 | inappropriate to do so should be disclosed.
- 30 | 23. The estimates of future federal royalty receipts on proved reserves known to
31 | exist as of the reporting date should be divided further by commodity and
32 | type (e.g., wet gas, **dry gas**, oil and **lease condensate**, onshore, offshore,
33 | etc.) and calculated separately if material differences would otherwise
34 | result. Each of the individual calculations should be summed together to
35 | arrive at the federal government's total estimated petroleum royalties.

⁴ Estimates that do not lead to material misstatements are acceptable without guidance from the Board.

⁵ See SFFAS 33, paragraphs 28 through 32.

Deleted: for additional guidance

24. The preferred measurement method for valuing the federal government's estimated petroleum royalties is the present value of future federal royalty receipts on proved reserves; however, another methodology may be acceptable if it is not reasonably possible to estimate present value.

Deleted: I
Deleted: the
Deleted: of future federal royalty receipts on proved reserves, then the value of the federal government's estimated petroleum royalties may be computed by multiplying the estimated quantity of proved oil and gas reserves under federal lands by the average first purchase price for oil or average wellhead price for gas and the effective average royalty rate by region. Other methodologies may be acceptable.

25. Once established, the estimation methodology should be consistently followed and disclosed in the financial reports. If environmental or other changes would provide for the development of an improved methodology, the nature and reason for the change in methodology, as well as the effect of the change, should be disclosed. The net effect of a change in methodology after the initial year should be accounted for as a change in accounting estimate effected by a change in accounting principle.⁶

26. A change in accounting estimate should be accounted for in (a) the period of change if the change affects that period only or (b) the period of change and future periods if the change affects both. A change in accounting estimate should not be accounted for by restating or retrospectively adjusting amounts reported in financial statements of prior periods or by reporting pro forma amounts for prior periods.⁷

Comment: From J. Farrell: Document should be clear whether this is a change in estimate or change in principle. Staff: Incorporated FAS 154 guidance into standard.

Liability Recognition

27. Upon collection, the majority of the federal government's estimated petroleum royalties from the production of federal oil and gas proved reserves are distributed to state governments, other federal agencies, and the general fund of the U.S. Treasury in accordance with legislated allocation formulas. The legislated allocation formulas constitute a present obligation⁸ of the component entity that is responsible for collecting royalties to provide assets to another entity, and the underlying legislation identifies the conditions under which these distributions will be made.

Formatted: Bullets and Numbering

28. A long-term liability and corresponding expense for estimated petroleum royalty revenue distributions to non-federal entities (e.g., state governments) should be recognized by the component entity that is responsible for

Comment: Staff note: For further discussion, refer to Issue Paper No. 3 at Appendix 1.
Formatted: Bullets and Numbering
Comment: Staff note: For further discussion, refer to Issue Paper No. 6 at Appendix 1.
Deleted: others
Deleted: states
Deleted: shall
Deleted: on the balance sheet of

⁶ A change in accounting estimate effected by a change in accounting principle is a change in accounting estimate that is inseparable from the effect of a related change in accounting principle. An example of a change in estimate effected by a change in principle is a change in the method of depreciation, amortization, or depletion for long-lived, nonfinancial assets.

⁷ Statement of Financial Accounting Standards (SFAS) 154, *Accounting Changes and Error Corrections (as amended)*, pars. 2e, and 19 – 21.

⁸ The term obligation is used in this Statement with its general meaning of a duty or responsibility to act in a certain way. It does not mean that an obligation of budgetary resources is required for a liability to exist in accounting or financial reporting or that a liability in accounting or financial reporting is required to exist for budgetary resources to be obligated.

collecting royalties in conjunction with the recognition of an asset for estimated petroleum royalties. The amount of the liability should be estimated based on the present value of the royalty share of the federal proved oil and gas reserves designated to be distributed to non-federal entities. For example, the average annual share of the revenue distributed to non-federal entities over the preceding twelve (12) months may be an acceptable basis for estimating petroleum royalties to be distributed. Other methodologies may be acceptable. The corresponding expense should be recognized in a manner consistent with existing standards.

Deleted: shall

Deleted: others, e.g., the states, the general fund of the U.S. Treasury and other federal agencies

Deleted: others

Deleted: to others

29. The estimated portion of the liability for royalty revenue distributions to non-federal entities expected to be distributed within 12 months of the fiscal year-end may be classified as current.

Comment: Staff note: For further discussion, refer to Issue Paper No. 3 at Appendix 1.

30. The cumulative net effect of recognizing an asset and establishing a liability for revenue distributions to non-federal entities at the beginning of the reporting period for which these standards are fully effective should be reported as a "change in accounting principle" that increases the entity's net position. The adjustment should be made to the beginning balance of cumulative results of operations on the statement of changes in net position for the period that the change is made in accordance with SFFAS 21, Reporting Corrections of Errors and Changes in Accounting Principles. In the initial year of implementation, prior year information should not be restated.

Deleted: shall

Inserted: shall

Deleted: would be

Deleted: shall

Deleted: shall

Revenue and Expense Recognition

31. Bonus bid and rent revenue relating to federal oil and gas resources should be recognized as exchange revenue on the statement of net cost of the component entity that is responsible for collecting royalty revenue.⁹ In addition, a liability¹⁰ and corresponding expense for bonus bid and rent revenue distributions to non-federal entities should be recognized by the component entity that is responsible for collecting royalties in conjunction with the recognition of the bonus bid and rent revenue. The amount of the liability should be the bonus bid and rent revenues designated to be distributed to non-federal entities, e.g., state governments. The

Formatted: Bullets and Numbering

Deleted: shall

Deleted: and/or transfer out

Deleted: others

Deleted: shall

Deleted: shall

Deleted: others

Deleted: the states

Deleted: , the general fund of the U.S. Treasury and other federal agencies

⁹ Per SFFAS 7, *Accounting for Revenue and Other Financing Sources*, paragraph 34.

¹⁰ SFFAS 1, *Accounting for Selected Assets and Liabilities*, par. 83-86, provides that other current liabilities may include unpaid expenses that are accrued for the fiscal year for which the financial statements are prepared and are expected to be paid within the fiscal year following the reporting date. Amounts of bonus bids and rent revenues to be distributed to non-federal entities may be classified as an other current liability consistent with SFFAS 1 if the definition is met.

1 | corresponding expense should be recognized in a manner consistent with
 2 | existing standards. Deleted: and/or transfer out
Deleted: shall

3 | **32. Royalties** from the production of federal oil and gas proved reserves should
 4 | be recognized as exchange revenue on the statement of net cost by the
 5 | component entity that is responsible for collecting the royalty revenue. At
 6 | the same time, an amount equal to the royalty revenue should be Deleted: shall
 7 | recognized as depletion expense on the statement of net cost of the
 8 | component entity that is responsible for collecting the royalty revenue and
 9 | the value of estimated petroleum royalties should be reduced by the Deleted: shall
 10 | depletion expense amount.¹¹

Future Royalty Rights Identified for Sale

12 | **33.** When rights to a stream of future royalties are identified for sale, the
 13 | calculated value of those rights should be disclosed in the notes as "future
 14 | royalty rights identified for sale." The "future royalty rights identified for sale"
 15 | should not be revalued or reclassified to a different asset category on the
 16 | balance sheet and no gain or loss should be reported prior to the sale. Formatted: Bullets and Numbering
Deleted: shall

17 | **34.** The calculated value disclosed for future royalty rights identified for sale
 18 | should be based on the specific field to be sold. Deleted: shall

19 | **35.** When the future royalty rights identified for sale are sold, the calculated
 20 | value of the future royalty rights sold should be removed from the estimated
 21 | petroleum royalties account at the time of the sale. Any difference between
 22 | this calculated value and the actual sales proceeds results in a net gain or
 23 | loss. Deleted: shall

24 | **36.** The net gain or loss should be reported on the statement of net cost of the
 25 | component entity that is responsible for collecting royalties. In addition, if
 26 | the sale produced a net gain, the liability and a corresponding expense for
 27 | the revenue distributions to non-federal entities should be increased by an
 28 | amount equal to the amount of the gain designated to be distributed to non-
 29 | federal entities, e.g., state governments. If the sale produced a net loss, the
 30 | liability and a corresponding expense for the revenue distributions to non-
 31 | federal entities should be decreased by an amount equal to the amount of
 32 | the loss, which will reduce future distributions to others. Deleted: shall
Deleted: and/or transfer-out
Deleted: others
Deleted: shall
Deleted: others
Deleted: the states
Deleted: , the general fund of the U.S. Treasury and other federal agencies
Deleted: and/or transfer-out
Deleted: others
Deleted: shall

¹¹ The principle that a liability is reduced when funds are distributed is established in other FASAB standards. When bonus bid, rent, and royalties are distributed, the liability for bonus bid, rent, and royalty distributions should be reduced.

Annual Valuation of Estimated Petroleum Royalties

37. The estimated petroleum royalties asset should be valued at the end of each fiscal year for financial statement reporting.

Formatted: Bullets and Numbering

Deleted: shall

38. The calculated value of estimated petroleum royalties at year-end should be compared to the existing book value of the estimated petroleum royalties asset. If the calculated value of the estimated petroleum royalties asset at year-end is greater than the book value,¹² the book value should be increased to the new estimate and a gain should be recognized on the statement of net cost. If the calculated value of the estimated petroleum royalties asset at year-end is less than the book value, the book value should be decreased to the new estimate and a loss should be recognized on the statement of net cost.

Comment: From DOI Field Test Team.

Deleted: shall

Deleted: shall

Deleted: shall

Deleted: recorded

Deleted: shall

Deleted: shall

Deleted: recorded

39. In addition, if the calculated value of the estimated petroleum royalties asset at year-end is greater or less than the book value, the liability for revenue distributions to non-federal entities should be increased or decreased to the amount expected to be distributed.¹³ If the revaluation resulted in a net gain, the liability and a corresponding expense for the revenue distributions to non-federal entities should be increased by an amount equal to the amount of the gain designated to be distributed to non-federal entities, e.g., state governments. If the revaluation resulted in a net loss, the liability and a corresponding expense for the revenue distributions to non-federal entities should be decreased by an amount equal to the amount of the loss, which will reduce future distributions to others.

Deleted: others

Deleted: shall

Deleted: and/or transfer-out

Deleted: others

Deleted: shall

Deleted: others

Deleted: the states

Deleted: , the general fund of the U.S. Treasury and other federal agencies

Deleted: and/or transfer-out

Deleted: others

Deleted: shall

40. For estimates that are developed using present value, component entities should display gains and losses from changes in **long-term assumptions** used to measure assets and liabilities for oil and gas as a separate line item or line items on the statement of net costs as required for pensions, ORB, and OPEB in SFFAS 33.¹⁴

Comment: From H. Steinberg: This is very important. I do not know whether the standard is referring to just changes in the interest rates, or it is referring to changes in the estimates of the quantities, costs of production, sales price, and/or timing of the sales.

Deleted: (Staff will explore the need for additional guidance on what would constitute a change in assumption for oil and gas vs. true gains and losses.)

¹² The estimated petroleum royalties beginning balance would have been reduced by the amount of depletion expense, recognized during the year.

Deleted: d on the statement of net cost

¹³ For example, the average annual share of the revenue distributed to others over the preceding twelve (12) months may be an acceptable basis to estimate future distributions. Other methodologies may be acceptable.

¹⁴ See SFFAS 33, paragraphs 19 through 27.

Deleted: for additional guidance

1 **Disclosures and Required Supplementary Information**

2 | **41.** Notes to the financial statements are an integral part of the basic financial
 3 | statements, essential for complete and fair presentation in conformity with
 4 | generally accepted accounting principles for the federal government.

Formatted: Bullets and Numbering

5 **Component Entity Disclosures**

6 | **42.** The component entity responsible for reporting the federal government's
 7 | estimated petroleum royalties on its balance sheet **should** provide the
 8 | following as note disclosures:

Formatted: Bullets and Numbering

Deleted: shall

- 9 a. A concise statement explaining how the management of federal
 10 oil and gas resources is important to the overall mission of the
 11 entity.
- 12
- 13 b. A brief description of the entity's stewardship policies for federal
 14 oil and gas resources. The stewardship policies for federal oil
 15 and gas resources **should** describe the guiding principles
 16 established to: assess the oil and gas resource areas; offer those
 17 resources to interested developers; sell and assign **leases** to
 18 winning bidders; administer the leases; collect bonuses, rents,
 19 royalties, and **royalty-in-kind**; and distribute the collections
 20 consistent with statutory requirements, prohibitions, and
 21 limitations governing the entity.
- 22
- 23 c. A narrative describing future royalty rights identified for sale, **if**
 24 **applicable**. The narrative **should** provide the value of the rights
 25 identified for future sale, the location of the field(s) involved in the
 26 future sale, and the best estimate of when the rights would be
 27 sold.
- 28
- 29 d. A narrative describing and a display showing earned revenue
 30 reported by category for the reporting period **should** be presented
 31 for offshore and onshore revenues for the following categories:
 32 royalty revenue earned for oil and gas, earned rent revenue,
 33 earned bonus bid revenue for leases, and total revenue from all
 34 the above categories.
- 35
- 36 e. A narrative describing and a display showing:
- 37
- 38 i. the quantity of oil and gas for each reporting period;
- 39

Deleted: shall

Comment: From Hal Steinberg:
define in the glossary.

Deleted: shall

Deleted: shall

- 1 ii. the average of the Regional Average **First Purchase Prices**
- 2 for oil and the average of the Regional Average **Wellhead**
- 3 **Prices** for gas for each reporting period;
- 4
- 5 iii. the average **royalty rate** for oil and gas for each reporting
- 6 period;
- 7
- 8 iv. the asset value for oil and gas by the commodities and types
- 9 identified for use in calculating the federal government’s total
- 10 estimated petroleum royalties for each reporting period (see
- 11 paragraph 23); and,
- 12
- 13 v. the value of estimated petroleum royalties at the end of each
- 14 reporting period.

15

16 f. The following reconciliation of beginning and ending estimated

17 petroleum royalties asset balances:

18

Formatted: Bullets and Numbering

<u>Beginning asset balance</u>	<u>\$XX,XXX</u>
<u>Revaluation Gain / Loss Due to Changes in:</u>	
<u>Quantity</u>	<u>XXX</u>
<u>Price</u>	<u>(XX)</u>
<u>Royalty Rates</u>	<u>XX</u>
<u>Assumptions</u>	
<u>Discount Rate</u>	<u>X,XXX</u>
<u>Inflation Rate</u>	<u>XXX</u>
<u>Less:</u>	
<u>Depletion</u>	<u>(XXX)</u>
<u>Sale of future royalty streams</u>	<u>(XX)</u>
<u>Ending asset balance</u>	<u>\$XX,XXX</u>

Formatted: Indent: Left: 0.08"

19

20 This reconciliation should provide all material components of the

21 changes in the estimated petroleum royalties asset consistent with

22 the components identified in the table immediately above, if

23 applicable. Additional sub-components may be presented. The line

24 item for revaluation gains and losses should be broken out into

25 sub-components for changes in quantity; price; royalty rates, if

26 applicable; and assumptions (i.e., discount rate and inflation rate).

27

Deleted: ¶
 <#>A narrative describing the estimation methodology used to calculate the value of the federal government’s estimated petroleum royalties. At a minimum, the narrative explanation should include a “plain English” explanation of the measurement method (e.g., present value) and the significant assumptions incorporated into the estimate (e.g., interest rates used to calculate present value).¶

Component Entity Required Supplementary Information (RSI)

43. The component entity responsible for reporting the federal government’s estimated petroleum royalties on its balance sheet should provide the following as RSI:

a. A narrative describing the estimation methodology used to calculate the value of the federal government’s estimated petroleum royalties. At a minimum, the narrative explanation should include a “plain English” explanation of the measurement method (e.g., present value) and the significant assumptions incorporated into the estimate (e.g., discount rates used to calculate present value, production decline curve, portion of proved reserves under federal lands, future oil and gas prices, inflation rates, etc).

b. An explanation of the significant components of the change in estimated petroleum royalties from one year to the next, the amounts associated with each type of change, and the reasons for the changes. The reasons should be explained as briefly as possible without detracting from understanding. Significant components of the change in estimated petroleum royalties include, but are not limited to, changes in quantity, price, royalty rates, discount rates, and inflation rates.

c. A reference to the source reports used to calculate the value of the federal government’s estimated petroleum royalties,

d. A narrative describing and a display showing the sales volume, the sales value, the royalty revenue earned, and the estimated value for royalty relief produced from federal oil and gas resources for the reporting period. To the extent that regional information is available, provide the information for each region.

Federal Receiving Entity Accounting and Reporting

44. Each federal entity that is required to receive a portion of the estimated petroleum royalties asset should disclose in the notes to its financial statements its relationship with the royalty revenue program and an estimate of the total amount of estimated petroleum royalties to be distributed to it by the component entity that is responsible for collecting royalties. The present value of the average annual share of the revenue distributed to each entity over the preceding twelve (12) months may be an acceptable basis for estimating the petroleum revenues to be distributed. Other methodologies may be acceptable.

Formatted: Bullets and Numbering

Deleted: shall

Formatted: Bullets and Numbering

Comment: From staff: For further discussion of changes, refer to Issue Paper No. 1 at Appendix 1.

Deleted: A narrative describing and a display showing the most current and complete information available for technically recoverable resources. The information shall include the estimated quantity of offshore technically recoverable resources from federal oil and gas resources, the estimated quantity of onshore technically recoverable resources from federal oil and gas resources, the as-of-date for the information being presented, and a brief explanation of changes to the information from the previous reporting period.

Formatted: Bullets and Numbering

Deleted: following information for each region that was identified for use in calculating the federal government’s total estimated petroleum royalties:¶¶
¶
The

Deleted: shall be added together in

Deleted: and reported

Deleted: ¶
A narrative describing and a display showing the following historical information about proved oil and gas reserves from federal leases for each of the preceding ten calendar years: adjustments; net revisions; revisions and adjustments; net of sales and acquisitions; extensions; new field discoveries; new reservoir discoveries in old fields; total discoveries; estimated production; proved reserves; and change from prior year. Definitions for these terms are contained in the Glossary under the subheading “Historical Estimates of Proved Reserves.”¶

Formatted: Bullets and Numbering

Comment: Staff note: For further discussion, see Issue Paper No. 6 at Appendix 1.

1 | 45. As distributions are received from the component entity responsible for
 2 | collecting royalties, the federal receiving entity should record an increase to
 3 | fund balance and a corresponding transfer in.

4 | **Consolidated Financial Report (CFR) of the United States Government**
 5 | **Disclosures**

6 | 46. The governmentwide entity should display gains and losses from changes in
 7 | assumptions as a separate line item or line items on the statement of net
 8 | cost after a subtotal for all other costs and before total cost. See the pro
 9 | forma illustration in Appendix B of SFFAS 33.

Formatted: Bullets and Numbering

10 | 47. The disclosure related to federal oil and gas resources should provide:

Deleted: shall

- 11 | a. A concise statement explaining the nature and valuation of federal oil
- 12 | and gas resources.
- 13 | b. A narrative describing and a display showing:
 - 14 | i. The quantity of oil and gas for each reporting period.
 - 15 | ii. The average of the Regional Average First Purchase Prices for oil
 - 16 | and the average of the Regional Average First Wellhead Prices for
 - 17 | gas for each reporting period.
 - 18 | iii. The average royalty rate for oil and gas for each reporting period.
 - 19 | iv. The asset value for oil and gas by the commodities and types
 - 20 | identified for use in calculating the federal government's total
 - 21 | estimated petroleum royalties for each reporting period (see
 - 22 | paragraph 23).
 - 23 | v. The value of estimated petroleum royalties at the end of each
 - 24 | reporting period.
- 25 | c. A reference to specific agency reports for additional information about
- 26 | oil and gas resources.
- 27 |

28 | **Disclosure Requirements for Fiduciary Oil and Gas Resources**

29 | 48. Fiduciary activities are defined in SFFAS 31, *Accounting for Fiduciary*
 30 | *Activities*. Information consistent with the requirements of paragraphs 14
 31 | through 40 of this document should be presented as an integral part of the
 32 | fiduciary activities Schedules of Fiduciary Activity and Net Assets. No
 33 | additional disclosures or RSI are required by this Statement.

Deleted: shall

Deleted: standard

Effect on Existing Standards

49. This Statement affects existing standards dealing with "bonus bid, rent, and royalty revenues" in SFFAS 7. As a result, paragraph 45 of SFFAS 7 is amended as follows:

[45] Under exceptional circumstances, such as revenues from the auction of the radio spectrum rents and royalties on the Outer Continental Shelf, an entity recognizes virtually no costs (either during the current period or during past periods) in connection with earning revenue that it collects.

50. In addition, paragraphs 275, 276, and 277 of SFFAS 7 are deleted.

[275.] MMS does not recognize a depletion cost for various reasons, including the fact that under present accounting standards natural resources are not recognized as an asset and depletion is not recognized as a cost. As a result, this exchange revenue bears little relationship to the recognized cost of MMS and cannot be matched against its gross cost of operations. Therefore, although the inflows are exchange revenue, they should not be subtracted from MMS's gross cost in determining its net cost of operations.

[276.] MMS collects rents, royalties, and bonuses and distributes the collections to the recipients designated by law: the General Fund, certain entities within the Government to which amounts are earmarked, the states, and Indian tribes and allottees. MMS collection activity for non-federal entities may meet the definition of fiduciary activity and, if so, should be accounted for in accordance with the requirements of SFFAS 31, Accounting for Fiduciary Activities. The amounts of revenue should be recognized and measured under the exchange revenue standards when they are due pursuant to the contractual agreement.

[277.] The rents, royalties, and bonuses transferred to Treasury for the General Fund, or to other Government reporting entities, should be recognized by them as exchange revenue. However, neither the Government as a whole nor the other recipient entities recognize the natural resources as an asset and depletion as a cost. Therefore, this exchange revenue should not offset their gross cost in determining their net cost of operations. It should instead be a financing source

Deleted: Implementation Guidance¶ The federal government's estimated petroleum royalties shall be recognized as an asset as of the beginning of the reporting period in which the standard

Deleted: s

Deleted: becomes fully effective. The estimated petroleum royalties shall be recognized on the balance sheet of the component entity responsible for collecting royalties. In addition, an offsetting liability shall be recognized for the amount of revenues designated for distribution to others. ¶

The cumulative net effect of adopting this proposed accounting standard shall be reported as a "change in accounting principle." The adjustment shall be made to the beginning balance of cumulative results of operations on the statement of changes in net position for the period that the change is made in accordance with SFFAS 21, Reporting Corrections of Errors and Changes in Accounting Principles. In the initial year of implementation, prior year information shall not be restated.

Inserted: s

Deleted: ¶

Formatted: Bullets and Numbering

Deleted: standard

Formatted: Bullets and Numbering

1 in determining their operating results and change in net
2 position.

3 **Effective Date**

4 | **51.** The following phase-in of reporting requirements as basic information
5 provides for full implementation for reporting periods beginning after
6 September 30, 2013.

Formatted: Bullets and Numbering

7 | a. ~~These standards are~~ effective for periods beginning after September
8 30, 2010.

Deleted: This

Deleted: i

Comment: From H. Steinberg: Is that enough time?

9 b. Information should be reported as RSI for the first three years of
10 implementation (fiscal years 2011, 2012, and 2013). Until such time
11 that the information is presented as basic, information reported as RSI
12 would be presented as part of a schedule of estimated petroleum
13 royalties and not reported in the principal financial statements.

Comment: Based on question from W. Jackson regarding presentation of RSI information.

14 c. Beginning in fiscal year 2014, the required information should be
15 presented as basic information, except where specifically designated as
16 RSI (paragraph 43).

17 d. Earlier implementation is encouraged.

18
The provisions of this Statement need not be applied to immaterial items.

1 Appendix A: Basis for Conclusions

2 This appendix discusses some factors considered significant by Board members in
3 reaching the conclusions in this Statement. It includes the reasons for accepting certain
4 approaches and rejecting others. Individual members gave greater weight to some
5 factors than to others. The standards enunciated in this Statement—not the material in
6 this appendix—should govern the accounting for specific transactions, events, or
7 conditions.

8 Project History

9 A1. The project began with the formation of a task force to conduct research. The
10 task force produced a discussion paper in June 2000 entitled *Accounting for*
11 *the Natural Resources of the Federal Government*. (See [http://www.fasab.gov/](http://www.fasab.gov/pdffiles/natresrpt.pdf)
12 [pdffiles/natresrpt.pdf](http://www.fasab.gov/pdffiles/natresrpt.pdf) to access the report.) In 2002, the Board resumed active
13 consideration of the issues raised by the task force after a deferral to address
14 other issues.

15 A2. The Board was interested in determining whether values for federal natural
16 resources, or some surrogate, should be capitalized and reported on the
17 balance sheet. The Board members believed that capitalizing federal natural
18 resources could increase accountability for their management and improve the
19 comprehensiveness, relevance, and consistency of federal financial
20 statements. The Board members agreed to address each type of natural
21 resource (e.g., fluid leasable minerals such as oil and gas, solid leasable
22 minerals such as coal and timber) in separate phases. Federal oil and gas
23 resources were addressed first because of the literature available in other
24 domains, the extensive historical information on federal lease programs and
25 royalty collections, and the large amount of revenue earned in exchange for oil
26 and gas resources.

27 A3. The Board indicated that the pertinent questions were (1) what, if anything,
28 should be recognized as an asset; and, (2) what is the source and reliability of
29 quantity information. They believed the source and the reliability of the
30 information would have a bearing on where information should be reported.

31 A4. The extractive industries' activities for oil and gas can be divided into two
32 categories—upstream activities (exploration and production activities) and
33 downstream activities (transportation, refining, and marketing activities).
34 Upstream activities can be divided into the following phases:

Deleted: are

- 1 a. Prospecting¹⁵
 2 b. Acquisition of mineral rights
 3 c. Exploration
 4 d. Appraisal and evaluation
 5 e. Development
 6 f. Production
- 7 A5. Downstream activities take place after the production phase of the upstream
 8 activities through to the point of sale and can be divided into the following
 9 phases:
- 10 a. Supply and trading
 11 b. Shipping
 12 c. Refining
 13 d. Storage and distribution
 14 e. Marketing and retail
- 15
- 16 A6. The national assessment of oil and gas resources performed by the federal
 17 government is similar to the prospecting phase of the extractive industries'
 18 upstream activities. It is the only activity performed by the federal government
 19 that is similar to the extractive industries' activities.
- 20 A7. The Board noted that, based on discussions about oil and gas lease activities
 21 in the private sector, new models for accounting and reporting the federal
 22 government's oil and gas activities would be needed because the current
 23 federal model is incomplete and federal activities are not similar to private
 24 sector activities.
- 25 A8. This exposure draft (ED) is the Board's second request for comments on its
 26 proposed requirements for accounting for federal oil and gas resources. The
 27 Board released the original ED, *Accounting for Federal Oil and Gas*
 28 *Resources*, on May 21, 2007. Substantive changes have been made to the
 29 original ED as a result of the comments received. Discussions about the new
 30 requirements as well as the changes from the original requirements are
 31 disbursed throughout the remainder of this appendix.

Comment: Comment from H. Steinberg: list phases of downstream activities to be consistent with par. A4.

Formatted: Bullets and Numbering

32 Overview of Federal Oil and Gas Resources

- 33 A9. *The Framework for Components of Federal Oil and Gas Resources*
 34 (framework) presented on page 41 identifies the universe of federal oil and gas

Formatted: Bullets and Numbering

¹⁵ Prospecting usually involves researching and analyzing an area's historic geologic data and carrying out topographical, geological, and geophysical studies.

1 resources. The framework presents accounting standards requirements and
 2 the components of federal oil and gas resources (total resources). Total
 3 resources incorporate “original in-place” resources, that is, resources in the
 4 earth before human intervention.

5 | A10. The accounting standards presented in the framework include current
 6 accounting standards and proposed accounting standards for each component
 7 of federal oil and gas resources. The components are those used in the
 8 industry. Information is available in varying degrees and with varying reliability
 9 for each component. The components are first separated into “undiscovered
 10 resources” and “discovered resources.” Generally, undiscovered resources
 11 are not under lease, while, discovered resources are under lease.

Deleted: ¶

12 | Undiscovered Resources

13 | A11. The first major component of total resources is **undiscovered resources**. The
 14 undiscovered resources component is divided into the following
 15 subcomponents:

Formatted: Bullets and Numbering

- 16 a. **undiscovered non-recoverable resources**
- 17 b. **undiscovered recoverable resources**
 - 18 i. **undiscovered conventionally recoverable resources**
 - 19 ii. **undiscovered economically recoverable resources.**

20 | A12. Each component and subcomponent can be further divided between onshore
 21 and offshore resources. Onshore resources consist of resources on federal
 22 lands. Offshore resources consist of resources on the Outer Continental Shelf
 23 (OCS). This division between onshore and offshore resources is important
 24 operationally because the source and volume of information varies.

Formatted: Bullets and Numbering

25 | A13. There is no information available on undiscovered non-recoverable resources.
 26 These resources are not addressed or included in any type of assessment.
 27 Undiscovered non-recoverable resources are referred to as resources that are
 28 beyond conventional technologies to be estimated and are not assessed.
 29 However, in the realm of “original in-place” resources they may exist.

30 | A14. Information on the two subcomponents of undiscovered recoverable resources
 31 is available for offshore oil and gas resources. This information is based on
 32 national assessments performed by the Minerals Management Service (MMS)
 33 approximately every 5 years, with updates on a yearly basis for certain
 34 geographic locations. The assessment considers recent geophysical,
 35 geological, technological, and economic information and uses a geologic **play**
 36 analysis approach for resource appraisal. Information on undiscovered

1 conventionally recoverable resources and undiscovered economically
2 recoverable resources is provided in the MMS assessment.

3 **A15.** For the onshore portion of undiscovered recoverable resources, the U.S.
4 Geological Survey (USGS) formerly conducted national assessments. The last
5 comprehensive national assessment was completed by the USGS in 1995, and
6 since 2000 the USGS has been re-assessing basins of the U.S. that are
7 considered to be priorities for the new assessment rather than assessing all of
8 the basins of the U.S. As each basin is re-assessed, the assessment results
9 are added to the assessment tables, and these new values replace the
10 assessment results from 1995. The USGS assessment provides information
11 on undiscovered conventionally recoverable resources but not on undiscovered
12 economically recoverable resources like the MMS does.

13 **A16.** Under current FASAB accounting standards, there are no requirements to
14 provide or present information about the undiscovered resource components in
15 the financial statements. Information about technically recoverable resources
16 has been gathered and maintained by the Energy Information Administration
17 (EIA) in the past. However, EIA no longer reports on the technically
18 recoverable resources under federal lands. Therefore, as there is no reliable
19 source for this type of information, federal reporting on onshore and offshore
20 undiscovered recoverable resources is not required.

Deleted: Under the proposed accounting standards, information about

Deleted: would be included in the technically recoverable resources and reported as required supplementary information (RSI)

Deleted: Information about technically recoverable resources has been gathered and maintained by the EIA in the past.

Formatted: Bullets and Numbering

21 Discovered Resources

22 **A17.** The second major component of total resources is **discovered resources**.
23 The discovered resources component is divided into the following
24 subcomponents as follows:

- 25 a. **unproved reserves**
 - 26 i. **unproved possible reserves**
 - 27 ii. **unproved probable reserves**
- 28 b. **proved reserves**
 - 29 i. **proved undeveloped reserves**
 - 30 ii. **proved developed reserves**
 - 31 i) **proved developed non-producing reserves**
 - 32 ii) **proved developed producing reserves**
- 33 c. **production**
- 34

1 | A18. Under current FASAB accounting standards, there are no requirements to
 2 | provide or present information about the unproved reserves components in the
 3 | financial statements.

Formatted: Bullets and Numbering

4 | A19. Under the accounting standards proposed in the original ED, information about
 5 | onshore and offshore unproved reserves would be included in the technically
 6 | recoverable resources and reported as RSI. However, as noted in par. A16,
 7 | although information about technically recoverable resources has been
 8 | gathered and maintained by the EIA in the past, EIA no longer reports on the
 9 | technically recoverable resources under federal lands. Therefore, as there is
 10 | no reliable source for this type of information, federal reporting on unproved
 11 | reserves is not required.

Comment: From H. Steinberg: The discussion of proposed and current acctng standards for unproved reserves are separated by pars. that discuss the availability of info for proved reserves; reorder pars. Staff reordered accordingly.

12 | A20. Quantitative information in relation to onshore and offshore proved reserves,
 13 | including new discoveries, production, and adjustments is submitted to the EIA
 14 | by oil and gas well operators once a year. The due date for operators to
 15 | submit the information is April 15 for activities from the preceding calendar
 16 | year.

17 | A21. Under current accounting standards, the bonus bid, rent (earned on the lease
 18 | until oil and gas production begins), and royalty revenue (earned on
 19 | production) are accounted for as a custodial activity (i.e., an amount collected
 20 | for others) by MMS-the collecting entity. The collections and their distribution
 21 | are reported on MMS's statement of custodial activities. Component entities
 22 | receiving a distribution and the CFR of the United States government
 23 | recognize the revenue as a financing source in their respective statement of
 24 | changes in net position or statement of operations and changes in net position.

Comment: From H. Steinberg

Deleted: revenue

Deleted: its

25 | A22. Under the proposed accounting standards, the estimated federal royalty share
 26 | of proved reserves would be recognized as estimated petroleum royalties by
 27 | the component entity responsible for reporting the asset on its balance sheet.
 28 | Also, royalty revenue earned would be recognized as revenue along with a
 29 | depletion expense in equal amounts on the statement of net cost. Changes in
 30 | the asset amount due to year-end valuation would be reported as a gain or loss
 31 | on the statement of net cost of the component entity responsible for reporting
 32 | the asset on its balance sheet. Also, revenue earned from rent and bonus bids
 33 | would be recognized as exchange revenue on the statement of net cost. Any
 34 | expenses incurred to collect the rent and bonus bids would be included in the
 35 | operating expenses on the statement of net cost. The CFR would include
 36 | these amounts in the consolidated financial statements.

Deleted: <#>Under the proposed accounting standards, information about onshore and offshore unproved reserves would be included in the technically recoverable resources and reported as RSI. Information about technically recoverable resources has been gathered and maintained by the EIA in the past. ¶ In addition, u

Deleted: collections for

37 | A23. There are no current requirements to provide or present information about the
 38 | production of oil and gas in the financial statements. However, under the
 39 | proposed accounting standards, information on the quantity and consumption

Deleted: historical

1 | of proved reserves, including the sales volume, the sales value, the amount of
 2 | royalty revenue earned, and the estimated value for royalty relief would be
 3 | provided as RSI.

Deleted: of proved reserves

Deleted: of proved reserves

4 | **A24.** The illustration in Appendix B: Illustration of the Components of Federal Oil and
 5 | Gas Resources provides a summary of the information presented in the
 6 | preceding paragraphs. The shaded boxes in the illustration represent the
 7 | availability of information as follows:

No quantity information available	
Technically recoverable resources quantity information provided by EIA ¹⁶	
Proved reserves quantity information provided by EIA ¹⁷	

8 | The terms in the illustration in Appendix B are defined in the Glossary
 9 | under the subheading *Definitions of Resource and Reserve Components*
 10 | *and Subcomponents*.

13 | **Conceptual Aspects of Federal Oil and Gas Resources as an Asset for**
 14 | **Estimated Petroleum Royalties and a Liability for the Portion of Revenue to be**
 15 | **Distributed to Non-Federal Entities**

Formatted: Indent: Left: 0.2"

Deleted: Others

16 | Recognition Criteria

17 | **A25.** SFFAC 5, *Definitions of Elements and Basic Recognition Criteria for Accrual-*
 18 | *Basis Financial Statements*, states that to be recognized as an element of the
 19 | financial statements, an item must (a) meet the definition of an element of the
 20 | financial statements and (b) be measurable. The term measurable means that
 21 | a monetary amount can be determined with reasonable certainty or is
 22 | reasonably estimable.¹⁸

Formatted: Bullets and Numbering

¹⁶ Quantity information is published at the national level.

¹⁷ Quantity information is published at the national level.

¹⁸ SFFAC 5, par. 5.

1 | A26. Measurement may require the use of estimates and approximations as well as
 2 | an assessment, in a manner consistent with the attribute being measured, of
 3 | the probability that future inflows or outflows of economic benefits or services
 4 | will result from the item. Recognition decisions also incorporate the results of
 5 | assessments of the materiality and benefit versus cost of recognizing the item
 6 | measured. Thus, it is possible that an item that meets the basic recognition
 7 | criteria would not be recognized due to measurement, materiality, or cost-
 8 | benefit considerations.¹⁹

9 | Asset Recognition

10 | A27. Recognition of the federal government's estimated petroleum royalties from the
 11 | production of federal oil and gas proved reserves as an asset is based on
 12 | SFFAC 5, paragraphs 18 through 35. Formatted: Bullets and Numbering

13 | A28. An asset for federal accounting purposes is a resource that embodies
 14 | economic benefits or services that the federal government controls.²⁰

15 | A29. To meet the definition of an asset of the federal government, a resource must
 16 | possess two characteristics. First, it must embody economic benefits or
 17 | services that can be used in the future. Second, the government must control
 18 | access to the economic benefits or services and, therefore, can obtain them
 19 | and deny or regulate the access of other entities.²¹

20 | *Oil and Gas Resources as a Federal Asset* Formatted: Indent: Left: 0.65"

21 | A30. First, the Board established which federal oil and gas resources were being
 22 | considered. Appendix B: Illustration of the Components of Federal Oil and Gas
 23 | Resources presents the oil and gas resources that were considered. The two
 24 | major components are "undiscovered resources" and "discovered resources."
 25 | All of the federal oil and gas resources qualify as federal government assets
 26 | because the government can obtain economic benefits and regulate the
 27 | access of other entities as provided under federal law. Formatted: Bullets and Numbering

28 | A31. Since all federal oil and gas resources controlled by the federal government
 29 | are assets, the Board's next step was to decide whether the federal oil and gas
 30 | resources "asset" should be recognized on a federal component entity balance
 31 | sheet. As noted in paragraph A25 above, the second criterion for recognition is
 32 | that the asset "...be measurable."

¹⁹ SFFAC 5, par. 7.

²⁰ SFFAC 5, par. 18.

²¹ SFFAC 5, par. 22.

1 A32. Estimates of the quantity of oil and gas resources other than proved reserves
 2 was available through EIA in the past. With this quantity information, a
 3 monetary measure was technically feasible and, therefore, the asset qualified
 4 for consideration for recognition. However, the Board does not believe that the
 5 information is sufficiently reliable to be recognized in a cost-beneficial manner.

Deleted: have been
Deleted: is
Deleted: s

6 A33. The EIA information on other than proved reserves is derived from sporadic
 7 and incomplete national assessments and annual submissions by oil and gas
 8 producers. This makes it particularly uncertain. In addition, since these
 9 reserves are not currently under lease, determining the royalty share may be
 10 misleading since it is a current value measure but the underlying asset may be
 11 restricted and production may never occur. For those resources that are not
 12 restricted, production may occur but the timing and amount of royalties are very
 13 uncertain. Thus, applying the same measurement technique to other than
 14 proved reserves may not result in a value that represents what it purports to
 15 represent. Therefore, federal oil and gas resources not yet in the 'proved
 16 reserves' category would not be recognized on the federal balance sheet due
 17 to concerns regarding reliability of the proposed measure.

Comment: From H. Steinberg: The two pars. that address the unreliability of other than proved reserves info. should be contiguous. Staff moved pars. accordingly.

18 A34. SFFAC 1, *Objectives of Federal Financial Reporting*, provides the following
 19 with respect to reliability:

Deleted: However, information on these quantities would be provided as RSI.

20 160. Financial reporting should be reliable; that is, the information
 21 presented should be verifiable and free from bias and should
 22 faithfully represent what it purports to represent. To be reliable,
 23 financial reporting needs to be comprehensive. Nothing material
 24 should be omitted from the information necessary to represent
 25 faithfully the underlying events and conditions, nor should
 26 anything be included that would likely cause the information to
 27 be misleading to the intended report user. Reliability does not
 28 imply precision or certainty, but reliability is affected by the
 29 degree of estimation in the measurement process and by
 30 uncertainties inherent in what is being measured. Financial
 31 reporting may need to include narrative explanations about the
 32 underlying assumptions and uncertainties inherent in this
 33 process. Under certain circumstances, a properly explained
 34 estimate provides more meaningful information than no estimate
 35 at all.

36 A35. Concerning the proved oil and gas reserves from federal oil and gas resources,
 37 the Board believes that both the quantity and the estimated federal royalty
 38 share would be reliable. Thus, in this case, since the quantity of the estimated
 39 federal proved oil and gas reserves can be reliably estimated and converted to
 40 monetary terms (estimated federal royalty share), the Board believes the

Formatted: Bullets and Numbering
Deleted: royalty share
Comment: From H. Steinberg: Clarify what is meant by "quantity of the estimated royalty share can be reliably estimated and converted to monetary terms."

1 estimated federal royalty share of proved oil and gas reserves should be
 2 recognized on the balance sheet.

3 Measurement Attributes and Methods Considered

4 **A36.** Concerning the dollar amount to be recognized for the estimated federal royalty
 5 share of proved reserves, the Board considered various measurement
 6 attributes²² and methods, including the following:

8 **A37.** Historical cost (historical proceeds) – The amount of cash, or its equivalent,
 9 paid to acquire an asset, commonly adjusted after acquisition for amortization
 10 or other allocations (SFAC 5, par. 67). ‘Historical cost’ was not a feasible
 11 option for valuing the oil and gas reserves because there is no ‘historical
 12 exchange price’ for the oil and gas reserves controlled by the federal
 13 government.

15 **A38.** Fair value – When market transactions are available, fair value is the same as
 16 market value. Fair value is the price that would be received to sell an asset or
 17 paid to transfer a liability in an orderly transaction between market participants
 18 at the measurement date (SFAS 157, par. 5). Information needed to estimate
 19 fair value is not available as there are no current transactions between market
 20 participants involving the sale of the federal royalty share for proved oil and gas
 21 reserves.

23 **A39.** Net realizable (settlement) value – The total non-discounted amount of cash, or
 24 its equivalent, into which an asset is expected to be converted in due course of
 25 business less direct costs, if any, necessary to make that conversion (SFAC 5,
 26 Par 67). The ‘net realizable value’ (NRV) requires a reasonable estimate of
 27 future flows (receipts and costs) associated with converting assets to cash.
 28 However, it may be difficult to reliably estimate the amount of the future flows
 29 of the federal royalty share for proved oil and gas reserves due to volatile
 30 fluctuations in the first purchase price for oil and wellhead price for gas.

32 **A40.** Present (or discounted) value of future cash flows – The present or discounted
 33 value of future cash inflows into which an asset is expected to be converted in
 34 due course of business less present values of cash outflows necessary to
 35 obtain those inflows (SFAC 5, Par 67). An estimate of the ‘present (or
 36 discounted cash) value’ of the estimated federal royalty share appeared to be
 37 most appropriate because the asset will be converted in future periods.

Deleted: ¶
 The EIA information on other than proved reserves is derived from sporadic and incomplete national assessments and annual submissions by oil and gas producers. This makes it particularly uncertain. In addition, since these reserves are not currently under lease, determining the royalty share may be misleading since it is a current value measure but the underlying asset may be restricted and production may never occur. For those resources that are not restricted, production may occur but the timing and amount of royalties are very uncertain. Thus, applying the same measurement technique to other than proved reserves may not result in a value that represents what it purports to represent. Thus, federal oil and gas resources not yet in the ‘proved reserves’ category would not be recognized on the federal balance sheet due to concerns regarding reliability of the proposed measure. However, information on these quantities would be provided as RSI.¶

Formatted: Bullets and Numbering

Formatted: Bullets and Numbering

Formatted: Bullets and Numbering

Deleted: Nor are there current transactions between market participants for the sale of rights to comparable future revenue streams.

Formatted: Bullets and Numbering

Deleted: cannot be reliably estimated for various reasons. The amount cannot be reliably estimated

Deleted: Reasons for these variations include:

Deleted: The permitting process for exploration, development, and production activities.¶
 <#>The lessee’s budget.¶
 <#>Other projects the lessee is focusing on.¶
 <#>The geological make-up of the earth.¶
 <#>The depth of the water or the depth of the wells for offshore wells.¶
 <#>The uncertainties of each well.¶
 <#>New discoveries.¶
 <#>Improved technology.¶
 <#>The economy and price volatility.¶
 Production incentives provided by the federal government.

Formatted: Bullets and Numbering

²² Measurement attribute – the traits or aspects of an element that can be quantified in monetary units with sufficient reliability (adapted from Statement of Financial Accounting Concepts (SFAC) 5: Recognition and Measurement in Financial Statements of Business Enterprises, as amended, par. 65).

1 However, the 'present (or discounted cash) value' method poses measurement
2 challenges because:

- 3
- 4 a. It is difficult to estimate the timing of future inflows.
 - 5 b. The discount rate should be commensurate with the riskiness of the
6 stream and each well might be viewed as having a unique level of risk.
 - 7 c. Prices are subject to fluctuation, making the amount of future inflows
8 volatileA39.
 - 9 d. It is difficult to estimate the time from when a lease is signed until
10 production begins (from 3 years to 20 years or more) and how long a
11 well will be productive.
- 12

13 **A41.** Based on the above, the Board had previously determined that none of the
14 measurement methods or attributes currently used in practice was a feasible
15 measure of the estimated federal royalty share for proved oil and gas reserves.
16 However, after reviewing the results of the field testing performed by the
17 Department of the Interior (DOI) and talking with DOI representatives about the
18 methodology that has been developed, the Board determined that present
19 value might be a feasible measure if the challenges presented in paragraph
20 A40 above can be reasonably overcome.

Formatted: Bullets and Numbering

21 *Asset Valuation Methodology*

22

23

24 **A42.** The Board believes that the detailed estimation methodology for valuing oil and
25 gas natural resources should be developed by federal entities rather than
26 centrally by the Board. In an environment heavily affected by changes in
27 prices, technological advancements, economic and operating conditions, and
28 known geological, engineering, and economic data, estimation methodologies
29 may need to be regularly updated to reflect changing economic and
30 technological conditions. Sources of information that were once available to
31 preparers may be replaced or become obsolete. On the other hand, new and
32 more reliable data sources may become available. Permitting the preparers
33 flexibility in developing an estimation methodology that keeps pace with the
34 environment will prevent the accounting standards from becoming outdated.

Formatted: Bullets and Numbering

35

36 **A43.** EIA has been used as the source of information on proved reserves data in the
37 past and may prove to continue to be the appropriate source for such
38 information in the future. However, the Board has chosen not to explicitly
39 designate EIA as the source of information in an attempt to prevent the
40 standards from becoming outdated if EIA were to stop reporting the minimum
41 information necessary to calculate the estimated petroleum royalties asset. In
42 addition to dating the standards, an explicit designation of the source of

Formatted: Bullets and Numbering

1 information would prevent the preparer from fully complying with the standards
2 if the source were no longer available at some point in the future.

3
4 *Change in Methodology after the Initial Year of Implementation*

← --- Formatted: Indent: Left: 0.65"

5
6 A44. The net effect of a change in methodology after the initial year should be
7 accounted for as a change in accounting estimate effected by a change in
8 accounting principle.

← --- Formatted: Bullets and Numbering

9
10 A45. A change in accounting estimate effected by a change in accounting principle
11 is a change in accounting estimate that is inseparable from the effect of a
12 related change in accounting principle. An example of a change in estimate
13 effected by a change in principle is a change in the method of depreciation,
14 amortization, or depletion for long-lived, nonfinancial assets (SFAS 154, par.
15 2e).

← --- Formatted: Bullets and Numbering

16
17 A46. Distinguishing between a change in an accounting principle and a change in an
18 accounting estimate is sometimes difficult. In some cases, a change in
19 accounting estimate is effected by a change in accounting principle. One
20 example of this type of change is a change in method of depreciation,
21 amortization, or depletion for long-lived, nonfinancial assets (hereinafter
22 referred to as depreciation method). The new depreciation method is adopted
23 in partial or complete recognition of a change in the estimated future benefits
24 inherent in the asset, the pattern of consumption of those benefits, or the
25 information available to the entity about those benefits. The effect of the
26 change in accounting principle, or the method of applying it, may be
27 inseparable from the effect of the change in accounting estimate. Changes of
28 that type often are related to the continuing process of obtaining additional
29 information and revising estimates and, therefore, are considered changes in
30 estimates for purposes of applying this Statement (SFAS 154, par. 20).

← --- Formatted: Bullets and Numbering

31
32 A47. Like other changes in accounting principle, a change in accounting estimate
33 that is effected by a change in accounting principle may be made only if the
34 new accounting principle is justifiable on the basis that it is preferable. For
35 example, an entity that concludes that the pattern of consumption of the
36 expected benefits of an asset has changed, and determines that a new
37 depreciation method better reflects that pattern, may be justified in making a
38 change in accounting estimate effected by a change in accounting principle
39 (SFAS 154, par. 21).

← --- Formatted: Bullets and Numbering

- 1 | *Use of Regional Data to Value the Federal Asset “Estimated Petroleum*
2 | *Royalties”* ← **Formatted:** Indent: Left: 0.65"
- 3 | **A48.** The Board believes that the most relevant, reliable, and cost-beneficial ← **Formatted:** Bullets and Numbering
4 | measurement of “estimated petroleum royalties” would be obtained by using
5 | regional information. The Board believes this approach would provide
6 | conservative, representative regional values of estimated petroleum royalties
7 | without having to calculate the value on a field-by-field basis. The Board
8 | believes it would not be practicable to make calculations on a field-by-field
9 | basis. There are more than 60,000 leases maintained by the DOI with
10 | approximately 115,000 producing wells.
- 11 | Liability Recognition
- 12 | **A49.** Recognition of royalty distributions to non-federal entities as a liability is based ← **Deleted:** others
13 | on SFFAC 5 paragraphs 36 through 48. ← **Formatted:** Bullets and Numbering
- 14 | **A50.** A liability is a present obligation²³ of the federal government to provide assets
15 | or services to another entity at a determinable date, when a specified event
16 | occurs, or on demand.²⁴
- 17 | **A51.** A liability of the federal government has two essential characteristics. First, a
18 | liability constitutes a present obligation to provide assets or services to another
19 | entity. Second, either a law or an agreement or understanding between the
20 | government and another entity identifies conditions or events that will
21 | determine when the obligation will be settled.²⁵
- 22 | **A52.** In paragraph 17, the Board proposes that the federal government’s estimated
23 | petroleum royalties be recognized as an asset on the balance sheet of the
24 | component entity that is responsible for collecting royalties. The asset’s value
25 | would be based on the royalty share of the federal oil and gas resources
26 | classified as “proved reserves.” In addition to the royalties that the component
27 | entity collects on proved reserves that are produced, it also collects lease sale
28 | and rent revenue from federal government oil and gas leases. The component
29 | entity distributes nearly all of these proceeds to others (e.g., the general fund of
30 | the U.S. Treasury, other federal agencies, and state governments) in ← **Deleted:** states
31 | accordance with legislated allocation formulas. The component entity also

²³ The term obligation is used in this Statement with its general meaning of a duty or responsibility to act in a certain way. It does not mean that an obligation of budgetary resources is required for a liability to exist in accounting or financial reporting or that a liability in accounting or financial reporting is required to exist for budgetary resources to be obligated.

²⁴ SFFAC 5, par. 39.

²⁵ SFFAC 5, par. 41.

1 receives a very small portion of the revenue collected to fund its operations.
 2 The amount used to fund its operations is legislated by Congress as part of the
 3 component entity's annual appropriation. For example, the amount received by
 4 the component entity was approximately one percent (1%) of annual revenues
 5 collected in 2005.

6 A53. The Board considered and agreed that a liability for revenue distributions to
 7 others should be recognized in conjunction with the recognition of an asset for
 8 estimated petroleum royalties. The Board believes a liability for revenue
 9 distributions to others should be recognized because nearly all of the revenue
 10 from royalties, lease sales, and rent are ultimately distributed to others (e.g.,
 11 the general fund of the U.S. Treasury, other federal agencies, and state
 12 governments). As the proceeds are distributed, the liability would be reduced.
 13 In addition, upon consolidation, the portion of the liability related to other
 14 federal agencies and the general fund of the U.S. Treasury would be
 15 eliminated so that the balance sheet for the government as a whole reports
 16 only the liability for amounts allocated to non-federal entities.

Deleted: an offsetting

Deleted: an offsetting

Deleted: the states

17 A54. The Board believes that if a liability for revenue distributions to others was not
 18 established, the component entity's and the federal government's net position
 19 would be overstated.

20 A55. Conceptually, it would be appropriate for the component entity to record a
 21 liability for the revenue to be distributed to both federal and non-federal parties.
 22 However, in its response to the field test questionnaires, the Department of the
 23 Interior (DOI) field test team notes that each designated federal recipient would
 24 be required to record a corresponding receivable and transfer in their
 25 statements, with eliminations between entities to prevent double counting
 26 government wide. The field test team notes that this accounting becomes
 27 especially critical at quarter-ends and at fiscal year-end, where late
 28 adjustments required to accruals that are deemed related to oil and gas
 29 revenue will also require late adjustments by all downstream recipients, thus
 30 significantly hampering entities' ability to meet accelerated financial reporting
 31 due dates and potentially giving rise to audit findings.

Formatted: Bullets and Numbering

32 A56. Recognizing that the federal government's current environment results in a
 33 continuing strain on resources, the Board has become even more sensitive to
 34 developing accounting requirements that serve to provide meaningful
 35 information to financial statement users while trying to avoid requirements that
 36 are complied with merely for the sake of compliance.

37 A57. The original ED requirements would result in each of the receiving federal
 38 entities recognizing an account receivable and a transfer in their financial
 39 statements for the initial asset entry. Then, as the asset is subsequently

1 revalued or adjusted by DOI or its auditors, the receiving federal entities would
2 need to adjust their accounts receivable and transfer accounts. In addition, the
3 intragovernmental elimination entries would need to be adjusted as well. This
4 would be a lot of last minute adjusting for amounts that would be eliminated
5 from the CFR. However, if the receivable entries were not made, the receiving
6 entities would not be including these assets in their financial statements. The
7 Board reconsidered the value of having the federal component entities record
8 the receivable and transfer in their financial statements.

9 A58. Accounts receivable arise from claims to cash or other assets (SFFAS 1, par.
10 40). The purpose of recognizing accounts receivable for accrual-basis
11 accounting is to recognize a resource that embodies economic benefits or
12 services in the period that it becomes measurable (SFFAC 5, pars. 5 and 18).
13 While the Board has decided that the estimated petroleum royalties asset upon
14 which the receivable would be based can be reasonably estimated, it is
15 doubtful that the federal receiving entity management would find much
16 decision-useful information with the recognition of a receivable that would be
17 extremely volatile and could not be relied upon for short or long-term budget
18 decisions. In addition, it is doubtful that the financial statement users would
19 find more value in recognition of a receivable on the face of the financial
20 statement as opposed to a disclosure of an estimated amount in the notes to
21 the financial statements. On the contrary, revaluations of the asset that result
22 in large inflows or outflows to the receiving entity in any given year would
23 require a detailed explanation to satisfy the user.

24 A59. The Board revised the requirements from the original ED so that only a liability
25 for revenue to be distributed to non-federal entities (e.g., state governments) is
26 required to be recognized while each federal receiving entity must disclose in
27 the notes to its financial statements its relationship with the royalty revenue
28 program and an estimate of the total amount of estimated petroleum royalties
29 to be distributed to it.

30 **Reporting the Gains and Losses from Changes in Assumptions and Selecting** 31 **Discount Rates**

32 A60. SFFAS 33, *Pensions, Other Retirement Benefits, and Other Postemployment*
33 *Benefits: Reporting the Gains and Losses from Changes in Assumptions and*
34 *Selecting Discount Rates and Valuation Dates*, requires that gains and losses
35 from changes in long-term assumptions used to estimate federal employee
36 pension, other retirement benefit (ORB), and other postemployment benefit
37 (OPEB) liabilities should be displayed on the statement of net cost separately
38 from other costs. This display provides more transparent information regarding
39 the underlying costs associated with certain liabilities. SFFAS 33 also provides

Formatted: Bullets and Numbering

standards for selecting the discount rate assumption and valuation date for pension, ORB, and OPEB liabilities.

A61. SFFAS 33 does not preclude entities from displaying or disclosing any information about the effect of changes in any assumptions with regard to other types of activities. The original SFFAS 33 ED had proposed a broad scope; however, although in principle a broader application was desirable, the Board decided to limit the standards to federal employee pension, ORB, and OPEB liabilities. This decision was based on the Board's desire to address more immediately its primary concern, which is to display the effect of assumption changes on employee compensation liabilities. Respondents had requested more guidance regarding how the standards would apply to other long-term assumptions; the Board believed that developing additional guidance would significantly delay implementation of SFFAS 33.

Formatted: Bullets and Numbering

A62. The Board believes that it would be appropriate to apply the guidance in SFFAS 33 to long-term assumptions about oil and gas in order to increase the usefulness of reported operating results when the volatility of projections results in large variations in annual net cost from year to year.

Comment: From H. Steinberg: describe why the Board believes that or delete the par.

Future Rights to Royalty Streams Identified for Sale

A63. When rights to a future royalty stream are identified to be sold, the value of those rights should be disclosed as "future royalty rights identified for sale." Future royalty rights identified for sale should not be revalued or reclassified to a different asset category on the balance sheet because the point in time for the sale of the future royalty rights may be uncertain and the identified fields may continue to produce oil and/or gas and generate royalties. These two factors make it difficult to establish and maintain valuation information in advance of the sale. No gain or loss on the future royalty rights identified for sale should be calculated since the rights for sale are only disclosed and are not revalued and reclassified to a different asset category on the balance sheet. Disclosure of the approximate value at the balance sheet date alerts the reader to the pending sale and the potential value of the asset to be sold.

Formatted: Bullets and Numbering

A64. The value of the disclosed future royalty rights identified for sale is based on the specific field identified for sale. Because the fields are known, this provides a more field specific value for the rights identified to be sold.

A65. At the time the future royalty rights identified for sale are sold, the calculated value of the future royalty rights sold would be calculated based on the specific field. An amount equal to this calculated value would be removed from the value of estimated petroleum royalties at the time of the sale. This calculation

1 is used to reduce the estimated petroleum royalties since the values of a
 2 specific field are known and the value of the future royalty rights sold can be
 3 more accurately calculated, which would provide a more realistic gain or loss
 4 on the sale. In addition, the liability for revenue distributions to non-federal
 5 entities should be adjusted by the amount of the gain or loss on the sale, if any,
 6 and reduced when the sale proceeds are distributed.

Deleted: others

7 Disclosures

8 A66. The Board proposes that various types and amounts of information be
 9 disclosed in the notes or provided as RSI. For example, one proposed
 10 disclosure would require a narrative describing and a display showing earned
 11 revenue reported by category for the reporting period. That is, royalty revenue
 12 earned for oil and gas, earned rent revenue, earned bonus bid revenue for
 13 leases, and total revenue. The proposed RSI includes sales volume, the sales
 14 value, the royalty revenue earned, and the estimated value for royalty relief for
 15 oil and gas produced from federal oil and gas resources for the reporting
 16 period. This information would be presented for each region, to the extent that
 17 regional information is available.

Formatted: Bullets and Numbering

Deleted: on a regional basis.
 Proposed RSI also includes a
 narrative describing and a display
 showing detailed historical
 information for the preceding ten
 calendar years.

18 Original Exposure Draft

19 A67. The original exposure draft (ED), *Accounting for Federal Oil and Gas*
 20 *Resources*, was issued May 21, 2007 with comments requested by September
 21 21, 2007. However, because the Board received a request for the comment
 22 period to be extended and because few responses had been received, the
 23 Board agreed to extend the comment period until January 11, 2008.

Formatted: Bullets and Numbering

24 A68. Upon release of the original ED, notices and press releases were provided to
 25 The Federal Register, *FASAB News*, *The Journal of Accountancy*, *AGA Today*,
 26 *the CPA Journal*, *Government Executive*, *the CPA Letter*, *Government*
 27 *Accounting and Auditing Update*, the CFO Council, the Presidents Council on
 28 Integrity and Efficiency, Financial Statement Audit Network, the Federal
 29 Financial Managers Council, and committees of professional associations
 30 generally commenting on exposure drafts in the past.

31 A69. This broad announcement was followed by direct mailings or e-mails of the
 32 original ED to:

- 33 a. relevant congressional committees (Senate Committee on Energy and
 34 Natural Resources, Senate Committee on Finance, Senate Committee on
 35 Indian Affairs, House Committee on Financial Services, House Committee
 36 on Natural Resources);

- 1 b. federal agencies (Office of Financial Management, Department of the
 - 2 Interior (DOI); Office of the Special Trustee (OST), DOI; Office of Financial
 - 3 Management, Department of Energy; Reserves and Products Division,
 - 4 Office of Oil and Gas, Energy Information Administration (EIA),
 - 5 Department of Energy; Office of the Chief Accountant, Securities and
 - 6 Exchange Commission (SEC));
 - 7 c. public interest groups (National Congress of American Indians (NCAI)
 - 8 President and Area (Regional) Vice Presidents); and,
 - 9 d. oil and gas industry companies/professional organizations ((World
 - 10 Petroleum Congress (WPC), American Petroleum Institute (API), Society
 - 11 of Petroleum Engineers (SPE), Ryder Scott Company, National Petroleum
 - 12 Council (NPC), International Energy Agency (IEA), British Petroleum (BP),
 - 13 Royal Dutch Shell, Chevron, Exxon Mobil)).
- 14 A70. To encourage responses, reminder notices were provided on September 12,
- 15 2007, and January 9, 2008, to the FASAB listserv. In addition, staff contacted
- 16 professional associations and affected agencies directly.

17 Comment Letters

18 A71. Eight comment letters were received from the following sources:

Formatted: Bullets and Numbering

	FEDERAL (Internal)	NON-FEDERAL (External)
Users, academics, others		4
Auditors	1	
Preparers and financial managers	3	

19 A72. The following points present a high-level summary of the comments received:

Formatted: Bullets and Numbering

- 21 a. The majority of respondents agreed with the overall concept of
- 22 recognizing an asset for the federal government’s natural resources and a
- 23 liability for the related royalty revenues designated to be distributed to
- 24 others.
- 25 b. Two of the eight respondents stated that ~~standards~~ on federal natural
- 26 resources should include all federal natural resources and not be limited to
- 27 only oil and gas resources.
- 28 c. One of the eight respondents commented on the complex nature of the
- 29 original ED.

Deleted: a

- 1 d. No respondents supported the use of the probabilistic method of
2 estimation as proposed in the alternative view of the original ED.
- 3 e. Two respondents supported the use of present value or fair value with
4 discounting (similar to the alternative view proposal) instead of the
5 valuation method as proposed in the original ED that utilizes the average
6 first purchase or wellhead price.
- 7 f. The majority of respondents agreed that the numerous disclosures
8 proposed in the original ED appeared excessive and might not pass a
9 cost/benefit test.
- 10 g. There was general support for royalty relief disclosures.
- 11 h. Of the five respondents that directly addressed the question on fiduciary
12 disclosures, four stated that the cost of such disclosures would outweigh
13 any perceived benefits.
- 14 i. The majority of respondents supported the recommendation for more
15 limited disclosures in the CFR. However, one respondent stated that
16 because natural resources are sovereign assets, the major disclosures
17 would more appropriately appear in the CFR and not agency financial
18 statements.

19 | A73. The Board did not rely on the number in favor of or opposed to a given
20 position. Information about the respondents' majority view is provided only as a
21 means of summarizing the comments. The Board considered the arguments in
22 each response and weighed the merits of the points raised.

Formatted: Bullets and Numbering

23 Field Testing

24 | A74. In addition to the comment letters received on the original ED, the Board also
25 considered the results of a field test of the proposed standards performed by a
26 DOI field test team. The field test team consisted of Minerals Management
27 Service (MMS) Offshore Minerals Management Economics and Resource
28 Evaluation experts and petroleum engineers; Bureau of Land Management
29 petroleum engineers and resource evaluation experts; and MMS Custodial
30 Reporting Branch senior accountants with expertise in financial reporting.

Formatted: Bullets and Numbering

31 | A75. Field tests are part of FASAB's due process and help FASAB to establish
32 effective standards. Participating federal entities volunteer to go through the
33 exercise of "implementing" the proposed standards s as if they were in place and
34 then provide feedback to FASAB regarding the process. Field tests can
35 proactively identify potential problems related to the implementation of

Deleted: it

- 1 proposed standards and allow FASAB to gather valuable information about
2 implementation costs.
- 3 | A76. The field test team presented the Board with a number of significant
4 considerations, including the lack of availability of quantity information on
5 proved reserves under federal lands. The original ED had proposed that the
6 valuation of oil and gas resources be based on information to be provided by
7 | EIA, on quantity of proved reserves under federal lands. However, this
8 information has not been made available as of the date of this revised ED, and
9 does not appear to be forthcoming.
- 10 | A77. In addition to the reliance on proved reserves data required to be provided by
11 EIA, the field test team noted a number of other concerns, including:
- 12 | a. the desire to divide proved reserves by type of commodity (e.g., crude oil,
13 lease condensate, and natural gas) and compute the asset value
14 separately;
- 15 b. the need to develop a methodology for determining what portion of all
16 proved reserves fall under federal domain;
- 17 c. the need to exclude royalty relief volumes and estimate the value of
18 commodities received in kind and delivered to the Department of Energy
19 to fill the Strategic Petroleum Reserve;
- 20 d. the effect of intermediate production between the effective date of the
21 reserves estimate and the effective date of the booked value;
- 22 e. the effect of estimates such as the royalty accrual and prior year
23 production adjustments made in the current year;
- 24 | f. how to distinguish between long and short-term liabilities for the
25 associated liability for revenue distributions to others;
- 26 g. appropriate treatment of interest payments related to oil and gas or
27 | commodities other than oil and gas once the custodial provisions are
28 deleted from SFFAS 7 (paragraphs 45, 275, 276, and 277);
- 29 h. the impact of material intragovernmental transactions and eliminations on
30 the year-end reporting process; and,
- 31 i. the need to revise all, or almost all, of the existing posting models in the
32 accounting system.

Deleted: the Energy Information Administration (

Deleted:)

Deleted: need

Deleted: other

1 | A78. The field test team also completed a field test questionnaire using a present
2 | value approach. This questionnaire included a lot of the same concerns as
3 | noted in paragraphs A76 and A77 above. In addition, the present value
4 | approach also incorporated present value calculations for factors such as the
5 | present value of royalties received over time, estimates of future gas prices,
6 | transportation allowances, and discount and inflation rates.

Formatted: Bullets and Numbering

7 | A79. In both estimates (the ED view as well as the present value view), the field test
8 | team used share of production as a proxy for share of proved reserves. One of
9 | the members expressed concerns about the use of production as a proxy for
10 | underlying reserves since it assumes (1) the same percentage of reserves are
11 | brought to market each year from all locations (or at least, on average between
12 | federal and non-federal) and (2) too much year to year variance in production
13 | patterns makes underlying reserve estimates fluctuate by an equal amount.

14 | A80. Staff asked an oil and gas analyst at the Congressional Budget Office for his
15 | thoughts on the methodology. He responded that he understands the concern
16 | with the first assumption because it is likely that not the same fraction of
17 | reserves will be accessed in each year. However, he stated that averaging
18 | between federal and non-federal would control for some of that variance,
19 | though it is not possible to know just how much. He stated that this simplifying
20 | assumption is fairly reasonable given the approximate nature of the analysis.
21 | The analyst noted that with the second assumption, the variance might be
22 | eliminated or reduced by using a moving average rather than a year to year
23 | measure. For example, a 5-year or 10-year moving average of total federal
24 | production over total production would control some of the yearly differences
25 | between federal and non-federal.

26 | A81. The field test questionnaires were extremely useful in helping the Board
27 | determine the focus of the current ED.

28 | Discussion with DOI Representatives

29 | A82. In addition to the Board's consideration of the comment letters received and
30 | the field test questionnaires, three members of the field test team and two
31 | representatives from the DOI Office of the Secretary met with the Board at the
32 | October 23, 2008, meeting to discuss issues raised in its comment letter on the
33 | original ED and the related field test questionnaires.

Formatted: Bullets and Numbering

34 | A83. At that meeting, the DOI representatives indicated that they would be open to
35 | having less detailed implementation guidance in the standards if they were
36 | given a longer implementation period (two to three years) with a phase-in from
37 | RSI to basic, and the ability to return to FASAB for implementation guidance if
38 | a reasonable methodology could not be agreed to by the auditors.

1 Significant Changes Made to the Original Exposure Draft

2 | **A84.** The significant changes made to the original ED as a result of the Board's
3 | consideration of the comments received, the field test questionnaires, and
4 | discussions with DOI representatives are summarized below:

Formatted: Bullets and Numbering

5 | a. Removed specific reference to “proved oil and lease condensate, **natural**
6 | **gas plant liquids (NGPLs)**, and gas reserves”; the revised ED refers
7 | more broadly to “proved oil and gas reserves.” Further breakdown by
8 | commodity and type of oil and gas will be considered by the federal entity
9 | as part of the estimation methodology.

Deleted: now

10 | b. Removed detailed asset valuation implementation guidance. Federal
11 | entities are provided flexibility in developing the estimation methodology
12 | for valuing oil and gas natural resources. In an environment heavily
13 | affected by changes in prices, technological advancements, economic and
14 | operating conditions, and known geological, engineering, and economic
15 | data, estimation methodologies may need to be regularly updated to
16 | reflect changing economic and technological conditions. The Board
17 | believes that the detailed estimation methodology for valuing oil and gas
18 | natural resources should be developed by federal entities rather than
19 | centrally by the Board.²⁶ The Board reached this conclusion based on
20 | discussions about recent changes that have occurred since the original
21 | ED was issued and the need to continually update the accounting
22 | standards as a result of volatile conditions in the oil and gas industry. The
23 | Board also considered DOI’s willingness to develop the methodology and
24 | work with the auditors to phase in the required reporting from RSI to basic
25 | over a period of two or three years and return to FASAB only on issues
26 | that could not be resolved with the auditors.

27 | c. Removed the illustrative disclosure and RSI presentations.

Deleted: <#>Simplified the detailed pro forma transactions; removed excess detail on how values were derived.¶

28 | d. Selected present value as the measurement method.

Formatted: Bullets and Numbering

29 | e. Stated that the preferred measurement method for valuing the federal
30 | government’s estimated petroleum royalties is the present value of future
31 | federal royalty receipts on proved reserves; however another methodology
32 | may be acceptable if it is not reasonably possible to estimate present
33 | value.

Deleted: Provided federal entities with the opportunity to compute the federal government’s estimated petroleum royalties by “multiplying the estimated quantity of proved oil and gas reserves under federal lands by the average first purchase price for oil or average wellhead price for gas and the effective average royalty rate by region” if it is not reasonably possible to estimate the present value of future federal royalty receipts on proved reserves. Other methodologies are deemed acceptable

²⁶ Estimates that do not lead to material misstatements are acceptable without guidance from the Board.

- 1 f. Permitted a change in methodology (see paragraphs 25 through 26) that
 2 is to be accounted for as a change in estimate effected by a change in
 3 principle.
- 4 g. Revised the component entity RSI disclosures.
- 5 h. Revised the requirement to recognize a liability for revenue distributions to
 6 others (e.g., the general fund of the U.S. Treasury, other federal agencies,
 7 and state governments) to only recognize the portion of the revenue to be
 8 distributed to non-federal entities (e.g., state governments).
- 9 i. Included a discussion of the classification of the liability for revenue to be
 10 distributed to non-federal entities as long-term vs. short-term.
- 11 j. Incorporated SFFAS 33 guidance for displaying gains and losses from
 12 changes in assumptions and selecting discount rates.
- 13 k. Incorporated accounting and disclosure requirements for the federal
 14 receiving entities.
- 15 l. Updated the effective date of the standards to provide for a three-year
 16 phase-in from RSI to basic information.
- 17 m. Moved the illustration of the components of federal oil and gas resources
 18 to an appendix by itself.
- 19 n. Updated the basis for conclusions.
- 20 o. Updated questions for respondents to request feedback on changes made
 21 to the original exposure draft.
- 22 p. [TBD based on discussion of other issues – fiduciary reporting, custodial
 23 reporting for other commodities, etc]

Deleted: "Once established, the estimation methodology should be consistently followed and disclosed in the financial reports. If environmental or other changes would provide for the development of an improved methodology, the nature and reason for the change in methodology, as well as the effect of the change, should be disclosed."

Deleted: long-term vs. short-term liability classification, detailed component entity RSI,

[This page intentionally left blank.]

[This page intentionally left blank.]

Deleted: And

Appendix C: Pro Forma Transactions ~~and~~ Financial Statements

PLEASE NOTE: The sample accounting entries and financial statements in Appendix C illustrate pro forma accounting transactions pertaining to federal oil and gas resources and the resulting financial statements. Data used in the pro forma transactions are based on hypothetical numbers for purposes of simplification. These illustrative examples are not intended to provide guidance on determining the application of materiality.

The following pro forma transactions are compressed and simplified, and appropriately do not contain all of the detail associated with an event. Budgetary and additional nominal account entries would be made by the collecting entity to track and report on greater detail than is illustrated in this appendix. For example, in transaction number two, the one-fifth bonus is invested until leases are accepted. Any interest accrued is refunded on bids subsequently rejected and returned. The illustration omits transactions internal to the entity. For example, transfers between sub-component entities are omitted. In addition, a greater degree of detail and certain reclassifications would occur in practice.

Comment: From H. Steinberg: It would be helpful to precede the entries with a brief narrative of the transaction that occurred in the entity. Staff is expanding the entries back to their original state from the May 2007 ED.

Comment: Included in field test response; see appendix 2, comment number 1.

Readers should not rely on the pro forma accounting transactions and resulting financial statements as a complete model for agency accounting. Certain omitted entries may be required in actual practice but are omitted since they are not required to understand the effect of the proposal on agency financial statements.

At the beginning of the fiscal year for which the accounting standards for oil and gas resources are effective, the following transaction is recorded by the component entity responsible for collecting royalties.

Deleted: is

Deleted: At the beginning of the fiscal year for which the accounting standard

Deleted: s

Deleted: for oil and gas resources

Deleted: are

Deleted: is effective, the following transaction is recorded by the component entity responsible for collecting royalties.

Inserted: is

Deleted: others

1. Record initial value of estimated petroleum royalties and the liability for revenue distributions to non-federal entities.

The initial value of estimated petroleum royalties used in this pro forma transaction is \$150,677,667, a hypothetical number used for illustrative purposes only. The actual value of the federal government's estimated petroleum royalties would be calculated on a regional basis and should approximate the present value of future royalty receipts on proved reserves known to exist as of the reporting date.

The illustrative pro forma entry to record the initial value of the federal government's estimated petroleum royalties as well as the liability for revenue to be distributed to non-federal entities is presented below. The asset's value would be the royalty share of the federal oil and gas resources classified as "proved reserves." The liability for revenue to be distributed to non-federal entities would be for the royalty share of the federal oil and gas resources classified as "proved reserves" designated to be distributed to non-federal entities, e.g., state governments. The proposed treatment of the distribution of revenue to non-federal entities creates a non-federal liability for the component entity responsible for collecting royalties.

Deleted: the states

The net effect of recognizing an asset and establishing a liability at the beginning of the reporting period would be a "change in accounting principle" in accordance with SFFAS 21, *Reporting Corrections of Errors and Changes in Accounting Principles.* The adjustment would be made to the beginning net position on the statement of changes in net position for the component entity responsible for collecting royalties in the period the change is made.

Deleted: and

Deleted: and other federal entities

Inserted: and other federal entities. For this illustration, 85 percent was used as the average annual share of the revenue distributed to the component entity responsible for collecting royalties and to other federal component entities based on the average distribution for 2005. To record the liability for revenue to be distributed to others

To obtain the value of the prior period adjustment, the total estimated petroleum royalties is multiplied by the average share of the revenue distributed to the component entity responsible for collecting royalties and other federal entities. For this illustration, 85 percent was used as the average annual share of the revenue distributed to the component entity responsible for collecting

royalties and to other federal component entities based on the average distribution for 2005. To record the liability for revenue to be distributed to non-federal entities, the total estimated petroleum royalties is multiplied by the average share of the revenue distributed to state governments and other non-federal entities. For this illustration, 15 percent was used as an average annual share of the revenue distributed to state governments and other non-federal entities based on the average distribution for 2005. These calculations are presented below:

$$\begin{aligned} & \$150,677,667 \times .85 = \$128,076,017 \text{ (federal portion)} \\ & \$150,677,667 \times .15 = \$22,601,650 \text{ (non-federal portion)} \end{aligned}$$

Dr Estimated Petroleum Royalties	150,677,667	
Cr Prior Period Adjustment: Change in Accounting Principle		128,076,017
Cr Liability for Revenue Distribution to Others – Non-Federal		22,601,650

To record initial value of estimated petroleum royalties due to change in accounting principle and the liabilities for revenue distributions to non-federal entities. (The 85% expected to be distributed to federal entities increases the net position of the entity responsible for making royalty collections)

Transactions two through ten will be recorded throughout the fiscal year by the component entity responsible for collecting royalties and, in some cases, the receiving federal entity.

2. Record payment of the one-fifth bonus bid amounts.

For a competitive lease sale, a notice of lease sale is published in the Federal Register. Each lease bid must include a payment for one-fifth of the bonus bid amount unless the bidder is otherwise directed by the Secretary. For purposes of this illustrative accounting event, four bonus bids were received with payment of the one-fifth bonus bid amount. Bonus bid number one was \$1,850, bonus bid number two was \$1,900, bonus bid number three was \$1,950, and bonus number four was \$2,000. The total payment relating to the four bonus bids was \$1,540 (bonus bid number one for \$370, bonus bid number two for \$380, bonus bid number three for \$390, and bonus bid number four for \$400) and was recorded with the following entry by the component entity responsible for collecting royalties.

Dr Fund Balance with Treasury	1,540	
Cr Unearned Revenue		1,540

To record collection of the one-fifth bonus bids for the four bonus bids.

3. Record remaining payment by the successful bidder and the annual rental fee and the liability for revenue distributions to non-federal entities.

Payment of the unpaid balance of the bonus bid amount and the first year's rental fee are to be received from the successful bidder on the 11th business day after receipt of the lease forms by the successful bidder. The successful bid was bonus bid number four in the amount of

- Deleted: others
- Deleted: the states
- Deleted: others
- Deleted: the states
- Deleted: others

- Deleted: 20,000
- Deleted: oun
- Deleted: ing
- Deleted: ¶
- Deleted: Cr Liability for Revenue Distribution to Others-Federal
- Deleted: 200
- Deleted: enue
- Deleted: istribution
- Deleted: States-
- Deleted: 14,000¶
5,800
- Deleted: state and local governments
- Deleted: and other federal component
- Deleted: 1
- Deleted: returned to
- Deleted: increases its net position.
- Formatted: Font: 11 pt
- Deleted: Other federal component entity entry:¶
- Deleted: others

1
2
3
4
5
6
7

8

\$2,000. The remaining four-fifths bonus bid of \$1,600 and the first year rental fee in the amount of \$360 is received. According to various legislative requirements, rental fees are required to be paid one year in advance and are recorded as revenue from rent when received because there is no obligation to refund unearned portions. The following entries are recorded by the component entity responsible for collecting royalties.

Dr Unearned Revenue
 Dr Fund Balance with Treasury
 Cr Revenue from Rent
 Cr Revenue from Bonus Bid

400
 1,960
 360
 2,000

To record remaining bonus payment and the annual rental fee by the successful bidder.

- Deleted: 1
- Deleted: ,0
- Deleted: 10,500
- Deleted: 0,00
- Deleted: 9
- Deleted: ,0

The increase in the liability for revenue distributions to non-federal entities is calculated by multiplying the revenue from rent and bonus bid by the average share of the revenue distributed to state governments and other non-federal entities. For this illustration, 15 percent was used as the average annual share of the revenue distributed to state governments and other non-federal entities based on the average distribution for 2005. This calculation is presented below:

$$\underline{\$2,360 \times .15 = \$354}$$

Dr Revenue Designated for Others – Non-Federal²⁹
 Cr Liability for Revenue Distribution to Others – Non-Federal

354
 354

To record the increase in the liability for revenue distributions to non-federal entities.

- Deleted: the states
- Deleted: the states
- Deleted: others

- Deleted: the States
- Deleted: ¶
- Dr Transfers-Out .
- Deleted: 1,725
- Deleted: Cr Liability for Revenue Distribution to Others-Federal¶

4. Receive the annual rental fee from pre-existing leases and record the liability for revenue distributions to non-federal entities.

For illustrative purposes, the total amount of annual rent collected for the year for offshore leases was \$193,274 and the rental fee for onshore leases was \$46,588 for a total of \$239,862. Since \$360 was received in connection with the new lease, the rental payments remaining are \$239,502 (\$239,862 less \$360). The following entry is recorded by the component entity responsible for collecting royalties.

Dr Fund Balance with Treasury
 Cr Revenue from Rent

239,502
 239,502

To record rental payments on leases for the year.

- Deleted: enue
- Deleted: States
- Deleted: -
- Deleted: 9,660¶
- Deleted: the future
- Deleted: others
- Deleted: Other federal component entity entry:¶
- Deleted: others
- Deleted: 1,000
- Deleted: 1,000
- Deleted: the states
- Deleted: others
- Deleted: the states
- Deleted: others

The increase in the liability for the rent revenue to be distributed to non-federal entities is calculated by multiplying the revenue from rent by the average share of the revenue distributed to state governments and other non-federal entities. For this illustration, 15 percent was used as an average annual share of the revenue distributed to state governments and other non-federal entities based on the average distribution for 2005. This calculation is presented below:

²⁹ This and certain other titles were selected for illustrative purposes. The entity has the option of selecting another account title, such as grant, that may be more appropriate.

1 | $\$239,502 \times .15 = \$35,925$
 2 | Dr Revenue Designated for Others – Non-Federal 35,925
 Cr Liability for Revenue Distribution to Others – Non-Federal 35,925

3 | *To record the increase in the liability for revenue distributions to non-federal entities.*
To record the accrual of a transfer-in and a reduction in the long-term A/R.

5. Refund unsuccessful bidders' bonus bid deposits.

Bonus bid deposits submitted by unsuccessful bidders are refunded to respective bidders after bids are opened, recorded, and ranked. Bonus bid number one in the amount of \$370, bonus bid number two in the amount of \$380, and bonus bid number three in the amount of \$390 for a total of \$1,140 are returned to respective bidders. The following entry is recorded by the component entity responsible for collecting royalties.

Dr Unearned Revenue 1,140
 Cr Fund Balance with Treasury 1,140
To record refund of losing bonus bids.

6. Record earned royalty revenue and depletion expense.

Earned royalty revenue should be recognized as exchange revenue by the component entity that is responsible for collecting the royalties. At the same time, an amount equal to the royalty collections should be recognized as depletion expense and the value of estimated petroleum reserves should be reduced by the depletion expense amount. Sales value and royalty payment information are due on or before the last of the month following the month the oil or gas produced from federal oil and gas resources was sold or removed from the lease. For example, oil or gas sold in June must be reported by July 31, the end of the following month.

For illustrative purposes, the total amount of royalty revenue earned for the fiscal year for offshore and onshore rental leases was used in this calculation. The royalty revenue earned during the fiscal year for offshore leases was \$3,563,922 and the royalty revenue earned during the fiscal year for onshore leases was \$852,331 for a total of \$4,416,253. The following entries are recorded by the component entity responsible for collecting royalties.

Dr Accounts Receivable 4,416,253
 Cr Revenue from Royalties for Federal Oil and Gas Reserves 4,416,253
To record earned royalty revenue.

Dr Oil and Gas Depletion Expense 4,416,253
 Cr Estimated Petroleum Royalties 4,416,253
To record depletion expense for federal oil and gas resources.

- Deleted: the States
- Deleted: 150
- Deleted: Dr Transfers-out¶
- Deleted: Cr Liability for Revenue Distribution to Others-Federal¶
- Deleted: enue
- Deleted: States
- Deleted: the future
- Deleted: others
- Deleted: Other federal component entity entry:¶ ... [3]
- Deleted: ¶
The remaining pro-forma transactions and financial statements are presented as of the end of the federal government's fiscal year (FY).¶
- Deleted: t
- Deleted: enue
- Deleted: 600
- Deleted: 600
- Deleted: 600
- Deleted: ¶
- Deleted: 600

7. Record collection of royalty revenue.

Royalty payments are due on or before the last of the month following the month the oil or gas produced from federal oil and gas resources are sold or removed from the lease, unless lease terms state that royalties are due otherwise. A year-to-date total of royalty revenue collected is in the amount of \$4,048,232. The following entry is recorded by the component entity responsible for collecting royalties.

Dr Fund Balance with Treasury	4,048,232	
Cr Accounts Receivable		4,048,232

To record collection of royalty revenue.

- Deleted: t
- Inserted: t from federal oil and gas resources are sold or removed from the lease, unless lease terms state that royalties are due otherwise. A year-to-date total of royalty revenue collected is in the amount of \$4,048,232. The following entry is recorded by the component entity responsible for collecting royalties.¶
- Deleted: 400
- Deleted: 400
- Deleted: others

8. Record distribution of bonus bid, rent, and royalty collections and the reduction in the liability for the revenue distributed to non-federal entities.

The component entity responsible for collecting royalty revenue is required to distribute the bonus bid, rent, and royalty revenue in accordance with authoritative formulas to recipients designated by law upon matching the revenue collections to specific leases. The component entity distributing bonus bid, rent, and royalty revenue from federal oil and gas resources should recognize the distribution to component entities in accordance with existing accounting standards. The federal component entity receiving the distribution should recognize the receipt as a transfer in when calculating its operating results. For purposes of this illustrative accounting event, the bonus bid collected was \$2,000, the rent collected was \$239,862 and the royalties collected was \$4,048,232 for total collections of \$4,290,094.

The bonus bid, rent, and royalty revenue collections distributed and the reduction in the liability for revenue distribution to non-federal entities is calculated in two parts. The first part is based on revenue collections designated as payments to non-federal entities while the second is based on collections designated as payments to other federal component entities. The revenue collections from bonus bid, rent, and royalties are multiplied by the average share of the revenue distributed to state governments and other non-federal entities to obtain the value of the collections to be distributed to non-federal entities. For this illustration, 15 percent was used as an average annual share of the revenue distributed to non-federal entities based on the average distribution for 2005. The revenue collections from bonus bid, rent, and royalties are multiplied by the average share of the revenue distributed to other federal component entities to obtain the value of the rent revenue to be distributed to other federal component entities. For this illustration, 84 percent was used as an average annual share of the revenue distributed to other federal component entities based on the average distribution for 2005. These calculations are presented below:

$$\begin{aligned}
 & \$4,290,094 \times .15 = \$643,514 \\
 & \$4,290,094 \times .84 = \$3,603,678
 \end{aligned}$$

Dr Liability for Revenue Distribution to Others – Non-Federal	643,514	
Dr Transfers-Out		3,603,678
Cr Fund Balance with Treasury		4,247,192

To record distribution of bonus bid, rent, and royalty revenue collections, the transfer out to other federal component entities, and the reduction in liabilities for revenue distribution to non-federal entities.

- Deleted: related
- Deleted: others
- Deleted: the states
- Deleted: others
- Deleted: Dr Liability for Revenue Distribution to Others-Federal¶
- Deleted: enue
- Deleted: States-
- Deleted: 10,710¶
- Deleted: 1,890
- Deleted: 12,600
- Deleted: others

1

Other federal entity entry:

Dr Fund Balance with Treasury
 Cr Transfer-in

3,603,678

3,603,678

To increase the fund balance with treasury and recognize a transfer-in for distributions received.

Deleted: 10,710

Deleted: Long-Term A/R for Oil and Gas-Federal

Deleted: 10,710

Deleted: reduce the long-term accounts receivable for oil and gas in relation to

9. Disclose rights to future royalty streams identified for sale.

When rights to a future royalty stream are identified to be sold, the value of those rights should be disclosed as future royalty rights held for sale. They should be disclosed rather than reclassified because (1) the point in time for the sale of the future royalty rights may be uncertain or undecided and (2) the identified fields may continue to produce oil and/or gas and generate royalties. These two factors make it difficult to establish and maintain precise valuation information in advance of the sale. Disclosure of the approximate value at the balance sheet date alerts the reader to the pending sale and the potential value of the asset to be sold. The value of the rights identified for sale should be based on the estimated quantity of proved reserves, the first purchase price for oil or the wellhead price for gas, and the royalty rate for each specific field identified for potential sale.

Future royalty streams from two specific oil fields have been identified to be sold sometime during the next fiscal year.

The estimated value of the future royalty stream identified to be sold from field number one is \$5,305 based on the following calculation: 1,000 barrels to be sold X \$42.44 per barrel per field number one first purchase price for oil X the 12.5% royalty rate for field number one.

The estimated value of the future royalty stream identified to be sold from field number two is \$3,245 based on the following calculation: 750 barrels to be sold X \$34.61 per barrel per field number two first purchase price for oil X the 12.5% royalty rate for field number two.

Deleted: . The future royalty streams are expected to be sold sometime during the next fiscal year

10. Record sale of future royalty streams identified for sale and the change in the liability for revenue distributions to non-federal entities.

Deleted: 9

Deleted: related

Deleted: others

At the time the future royalty rights identified for sale are sold, the asset value is calculated based on the quantity of proved oil reserves involved in the sale, the first purchase price or the wellhead price for the field at the time of sale, and the royalty rate for the specific field. Any difference between the asset value of the future royalty rights sold and the sales proceeds results in a net gain or loss. The net gain or loss should be reported on the statement of net cost of the component entity responsible for collecting royalty revenue. For purposes of this illustrative accounting event, the rights to future royalty rights held for sale for field number one had an asset value of \$5,375 based on the following calculation: 1,000 barrels of proved oil reserves involved in the sale multiplied by an arbitrary \$43.00 per field number one first purchase price per barrel further multiplied by the arbitrary 12.5 percent royalty rate for field number one. The rights to a future royalty stream from field number one were sold for \$3,950. As a result, there is a loss of \$1,425 on the sale of the future royalty stream from field number one, which should be reported on the statement of net cost.

Dr. Fund Balance with Treasury 3,950
 Dr. Loss on Sale of Estimated Petroleum Royalties 1,425
 Cr. Estimated Petroleum Royalties 5,375

- Deleted: 750
- Deleted: 150
- Deleted: 900

To record sale of future royalties.

The loss on the sale of estimated petroleum royalties is multiplied by the average share of the revenue distributed to state governments and other non-federal entities to obtain the reduction in the liabilities for revenue distributions to non-federal entities. For this illustration, 15 percent was used as an average annual share of the revenue distributed to state governments and other non-federal entities based on the average distribution for 2005. The revenue collections from bonus bid, rent, and royalties are multiplied by the average share of the revenue distributed to other federal component entities to obtain the value of the rent revenue to be distributed to other federal component entities. For this illustration, 84 percent was used as an average annual share of the revenue distributed to other federal component entities based on the average distribution for 2005. These calculations are presented below:

- Deleted: the states
- Deleted: others
- Deleted: related
- Deleted: the states
- Deleted: others

$$\begin{aligned} & \$1,425 \times .15 = \$214 \\ & \$1,425 \times .84 = \$1,197 \end{aligned}$$

Dr Liability for Revenue Distributions to Others – Non-Federal 214
 Cr Revenue Designated for Others – Non-Federal 214

- Deleted: Dr Liability for Revenue Distributions to Others- Federal ¶
- Deleted: States-
- Deleted: 127
- Deleted: the States
- Deleted: Cr Transfers-Out

To record the reduction in the liabilities and revenue designated for non-federal entities as a result of the loss on the sale of estimated petroleum royalties

$$\begin{aligned} & \$3,950 \times .15 = \$593 \\ & \$3,950 \times .84 = \$3,318 \end{aligned}$$

Dr Transfers-Out
 Dr Liability for Revenue Distributions to Others – Non-Federal 3,318
 Cr Fund Balance with Treasury 593
3,911

- Deleted: for the future revenue distributions to others
- Deleted: the States,
- Deleted: and transfers-out
- Deleted: 756
- Deleted: Dr Liability for Revenue Distributions to Others- Federal ¶
- Deleted: States-
- Deleted: 135

To record the distribution of collections from the sale of revenue streams, the transfer out to other federal component entities, and the reduction in the liability for revenue distributions to non-federal entities.

Other federal entity entry:

Dr. Fund Balance with Treasury 3,318
 Cr. Transfer-in 3,318

- Deleted: 756
- Deleted: Long-Term A/R for Oil and Gas-Federal

To increase the fund balance with treasury and recognize a transfer-in for distributions received.

At the end of each fiscal year, the following transaction is recorded by the component entity responsible for collecting royalties.

- Deleted: ¶

11. Record annual valuation of estimated petroleum royalties and the change in the liability for revenue distributions to non-federal entities.

The calculated value of the federal government’s estimated petroleum royalties for financial statement reporting at year-end should be compared to the book value of estimated petroleum royalties at year-end. If the calculated value of estimated petroleum royalties at year-end is greater than the year-end book value, the book value should be increased to the new estimate and a gain should be recorded on the statement of net cost of the reporting entity responsible for collecting revenue. If the calculated value of estimated petroleum royalties at year-end is less than the year-end book value, the book value should be decreased to the new estimate and a loss should be recorded on the statement of net cost of the reporting entity responsible for collecting royalty revenue. For illustrative purposes, the valuation of estimated petroleum royalties as of as of the year ended September 30 produced a gain of \$25,210,226 that is based on the following calculations.

The revaluation value of estimated petroleum royalties for oil and gas is hypothetically valued at \$171,466,265. The current value of estimated petroleum royalties (\$171,466,265) less the book value of estimated petroleum royalties (the initial value of estimated petroleum royalties at the beginning of the year (October) less depletion expense for estimated petroleum royalties through the end of the year (September 30), less the asset value of estimated petroleum royalties sold), equals the net gain to be recorded:

$$\$171,466,265 - (150,677,667 - 4,416,253 - 5,375) = \$25,210,226$$

Dr Estimated Petroleum Royalties 25,210,226
 Cr Gain on Revaluation of Estimated Petroleum Royalties³⁰ 25,210,226

- Deleted: 5,000
- Deleted: 5,000

To record revaluation of estimated petroleum royalties.

To record the increase in the liability for the revenue distributions to non-federal entities, the amount that the total estimated petroleum royalties was increased due to revaluation is multiplied by the average share of the revenue distributed to state governments and other non-federal entities. For this illustration, 15 percent was used as an average annual share of the revenue distributed to state governments and other non-federal entities based on the average distribution for 2005.³¹ This calculation is presented below:

$$\$25,210,226 \times .15 = \$3,781,534$$

Dr Revenue Designated for Others – Non-Federal 3,781,534
 Cr Liability for Revenue Distributions to Others – Non-Federal 3,781,534

- Deleted: the states
- Deleted: the states
- Deleted: the States
- Deleted: 750
- Deleted: Dr Transfers-Out¶
- Deleted: Cr Liability for Revenue Distributions to Others-Federal ¶
- Deleted: States-
- Deleted: 4,250¶
750¶
- Deleted: future
- Deleted: others
- Deleted: Other federal component entity entry:¶
- Deleted: entries

To record the year-end increase in the liabilities for the revenue distributions to non-federal entities.

1
2
3
4 The pro forma financial statements that follow are illustrative of the departmental entries presented in this appendix. The “other federal component entity” [financial statements](#) and the consolidated financial statements of the United States Government are not illustrated.

³⁰ This gain will be illustrated on the statement of net cost as partially due to changes in assumptions. This display is further illustrated in SFFAS 33.

³¹ See footnote 40.

[This page intentionally left blank.]

The following pro forma financial statements are illustrative of the presentation of basic information. Until such time that the information is presented as basic, information reported as RSI would be presented as part of a schedule of estimated petroleum royalties and not reported in the principal financial statements.

Comment: From W. Jackson: Distinguish between presentation for RSI information and basic information.

Pro Forma Financial Statements – for fiscal year ended 9/30/20XX

Balance Sheet

Assets

Fund Balance with Treasury	\$ 42,941
Accounts Receivable	368,021
Estimated Petroleum Royalties	<u>171,466,265</u>
Total Assets	\$ <u>171,877,227</u>

Deleted: 159
 Deleted: 200
 Deleted: 23,500
 Deleted: 23,859

Liabilities

Liability for Revenue Distributions to <u>Others – Non-Federal</u>	<u>25,775,142</u>
Total Liabilities	<u>25,775,142</u>

Deleted: Liability for Revenue Distributions to Others-Federal¶

Net Position

Cumulative Results of Operations	<u>146,102,085</u>
Total Liabilities and Net Position	\$ <u>171,877,227</u>

Deleted: States
 Deleted: -
 Deleted: 17,167¶
 6,377
 Deleted: 23,544
 Deleted: 315
 Deleted: 23,859

Statement of Net Cost

Oil and Gas Resources Program

Leasing Activities:

Costs (Oil and Gas Depletion Expense)	\$ 4,416,253
Less: Earned Revenue	<u>(4,658,115)</u>
Net Cost/(Revenue) from Leasing Operations	<u>(241,862)</u>

Deleted: 600
 Deleted: 13,100
 Deleted: 12,500

Loss/(Gain) on Revaluation of Estimated Petroleum Royalties	<u>(25,010,226)</u>
---	---------------------

Deleted: 3,000

Less: Revenue Designated for <u>Others – Non-Federal</u>	<u>3,817,599</u>
Less: Loss on Sale of Future Royalty Rights	<u>1,425</u>

Deleted: the States
 Deleted: 2,602
 Deleted: 150

Net Cost/(Revenue) for Program before (gain)/loss from changes in assumptions	\$ <u>(21,433,064)</u>
---	-------------------------------

Deleted: 12,748

(Gain)/Loss on assumption changes: Discount rate assumption Other assumptions Net (gain)/loss on assumption changes Net Cost/(Revenue) for Program <u>Statement of Changes in Net Position</u> Beginning Net Position Adjustment: Change in Accounting Principle Beginning Balance, as adjusted Net Revenue for Program Transfers In/(Out) Ending Net Position	<hr/> (200,500) 500 <hr/> (200,000) <hr/> \$(21,633,064) \$ 0 <hr/> 128,076,017 <hr/> 128,076,017 21,633,064 <hr/> (3,606,996) <hr/> \$ 146,102,085	<div style="border: 1px solid red; border-radius: 5px; padding: 2px; margin-bottom: 5px;">Deleted: 14,748</div> <div style="border: 1px solid red; border-radius: 5px; padding: 2px; margin-bottom: 5px;">Deleted: 200</div> <div style="border: 1px solid red; border-radius: 5px; padding: 2px; margin-bottom: 5px;">Deleted: 200</div> <div style="border: 1px solid red; border-radius: 5px; padding: 2px; margin-bottom: 5px;">Deleted: 14,748</div> <div style="border: 1px solid red; border-radius: 5px; padding: 2px; margin-bottom: 5px;">Deleted: 14,633</div> <div style="border: 1px solid red; border-radius: 5px; padding: 2px;">Deleted: 315</div>
--	--	--

1 **Appendix D: Abbreviations**

2	Bbl	Barrels
3	CFR	Consolidated Financial Report
4	CFR	Code of Federal Regulations
5	DOI	Department of Interior
6	ED	Exposure Draft
7	EIA	Energy Information Administration
8	FASAB	Federal Accounting Standards Advisory Board
9	FASB	Financial Accounting Standards Board
10	GAAP	Generally Accepted Accounting Principles
11	Mcf	Thousand Cubic Feet
12	MMS	Minerals Management Service
13	OCS	Outer Continental Shelf
14	NGPLs	Natural Gas Plant Liquids
15	RSI	Required Supplementary Information
16	SEC	Securities and Exchange Commission
17	SFAC	Statement of Financial Accounting Concepts
18	SFFAC	Statement of Federal Financial Accounting Concepts
19	SFAS	Statement of Financial Accounting Standards
20	SFFAS	Statement of Federal Financial Accounting Standards
21	U.S.	United States
22	USGS	U.S. Geological Survey

Deleted: API . American Petroleum Industry¶

Deleted: BLM . Bureau of Land Management¶

[This page intentionally left blank.]

1 **Appendix E: Glossary**

2 -----

3

4

Definitions of Resource and Reserve Components and Subcomponents

5

6

Provided below are definitions used by federal entities to describe oil and gas resource and reserve components and subcomponents. The source of these definitions is OCS Report MMS 2003-050 unless otherwise noted.

7

8

9

Resources estimated from broad geologic knowledge or theory and existing outside of known fields or known accumulations are undiscovered resources. Undiscovered resources can exist in untested prospects on unleased acreage, or on undrilled lease acreage, or in known fields. In known fields, undiscovered resources occur in undiscovered pools that are controlled by distinctly separate structural features or stratigraphic conditions.

10

11

12

13

14

15

16

17

18

19

20

21

22

23

The Mineral Management Service (MMS) and the U.S. Geological Survey (USGS) formerly conducted national assessments of undiscovered oil and gas resources together. The former was responsible for the offshore while the latter was responsible for onshore and state waters. The last such assessment was in 1995. MMS updates their assessment approximately every five years in accordance with the Department of Interior's five-year leasing program, with the last update in 2000. Since 1995, the USGS has not conducted an overall update for onshore and state waters, but has conducted assessments updates on a **basin** or area level.

24

25

26

27

Undiscovered Resources

28

29

30

31

32

33

Undiscovered resources are **hydrocarbons** estimated on the basis of geologic knowledge and theory to exist outside of known accumulations. They are presumed to occur in unmapped and unexplored areas. The speculative and hypothetical resource categories comprise undiscovered resources. Undiscovered resources are classified as either "undiscovered non-recoverable resources" or "undiscovered recoverable resources".

34

35

- Undiscovered Non-Recoverable Resources

36

37

38

The portion of undiscovered petroleum-initially-in-place quantities not currently considered to be recoverable. A portion of these quantities may become recoverable in the future as commercial circumstances change, technological developments occur, or additional data ~~are~~ acquired.

Comment: From H. Steinberg

Deleted: is

39

40

- Undiscovered Recoverable Resources

41

42

43

44

An assessment provides estimates of undiscovered recoverable resources in two categories for federal offshore oil and gas resources. However assessments for federal onshore oil and gas resources provide information for only one, the undiscovered, conventionally recoverable resources. Both are described below:

- 1
2 1. Undiscovered, conventionally recoverable resources: The portion of the hydrocarbon
3 potential that is producible, using present or reasonably foreseeable technology, without
4 any consideration of economic feasibility.
- 5 2. Undiscovered, economically recoverable resources: The portion of the undiscovered
6 conventionally recoverable resources that is economically recoverable under imposed
7 economic scenarios.

8 **Discovered Resources**

9
10 Once leased acreage is drilled and is determined to contain oil or gas under Code of Federal
11 Regulations (CFR) Title 30, Part 250, Subpart A, Section 11, Determination of Well Producibility
12 (hereinafter referred to as 30 CFR 250.11), the lease is considered to have discovered
13 resources.

14
15 Identified resources are resources whose location and quantity are known or are estimated from
16 specific geologic or engineering evidence and include economic, marginally economic, and
17 subeconomic components.

18 **Reserves**

19
20 In accordance with the Society of Petroleum Engineers (SPE), the World Petroleum Congresses
21 (WPC), and the American Association of Petroleum Geologists (AAPG), the definition for
22 “reserves” and the following explanatory paragraphs are presented as follows³²:

23
24 “Reserves are those quantities of petroleum which are anticipated to be commercially
25 recovered from known accumulations from a given date forward. All reserve estimates
26 involve some degree of uncertainty. The uncertainty depends chiefly on the amount of
27 reliable geologic and engineering data available at the time of the estimate and the
28 interpretation of these data.”

29 The relative degree of uncertainty may be conveyed by placing reserves into one of two
30 principal classifications, either 1) unproved or 2) proved.

31 **Unproved Reserves**

32
33
34 After a lease qualifies under 30 CFR 250.11, the MMS Field Naming Committee reviews the
35 new producible lease to assign it to an existing field or, if the lease is not associated with an
36 established geologic structure, to a new field. Regardless of where the lease is assigned, the
37 reserves associated with the lease are initially considered to be unproved reserves. Unproved
38 reserves are based on geologic or engineering information similar to that used in estimates of
39 proved reserves; but technical, contractual, economic, or regulatory uncertainties preclude such
40 reserves from being classified as proved.

41
42 Unproved reserves may be divided into two subclassifications, possible and probable,
43 which are similarly based on the level of uncertainty.

³² WPC/SPE/AAPG Petroleum Reserves and Resources Definitions.

1
2 "Unproved possible reserves are less certain than unproved probable reserves and can
3 be estimated with a low degree of certainty, which is insufficient to indicate whether they
4 are more likely to be recovered than not. Reservoir characteristics are such that a
5 reasonable doubt exists that the project will be commercial" (SPE, 1987). After a lease
6 qualifies under 30 CFR 250.11, the reserves associated with the lease are initially
7 classified as unproved possible.

8
9 "Unproved probable reserves are less certain than proved reserves and can be
10 estimated with a degree of certainty sufficient to indicate they are more likely to be
11 recovered than not" (SPE, 1987). Reserves in fields for which a schedule leading to a
12 Development and Production Plan (DPP) has been submitted to the MMS have been
13 classified as unproved probable.

14 **Proved Reserves**

15
16
17 "Proved reserves can be estimated with reasonable certainty to be recoverable under
18 current economic conditions, such as prices and costs prevailing at the time of the
19 estimate. Proved reserves must either have facilities that are operational at the time of the
20 estimate to process and transport those reserves to market or a commitment or
21 reasonable expectation to install such facilities in the future" (SPE, 1987). Proved
22 reserves can be subdivided into undeveloped and developed.

23
24 **Proved undeveloped reserves** are classified proved undeveloped when a relatively
25 large expenditure is required to install production and/or transportation facilities, a
26 commitment by the operator is made, and a timeframe to begin production is
27 established. Proved undeveloped reserves are reserves expected to be recovered from
28 (1) yet undrilled wells, (2) deepening existing wells, or (3) existing wells for which a
29 relatively large expenditure is required for recompletion.

30
31 **Proved developed reserves** are classified as proved developed when the reserves are
32 expected to be recovered from existing wells (including reserves behind pipe). Reserves
33 are considered developed only after necessary production and transportation equipment
34 have been installed or when the installation costs are relatively minor. Proved developed
35 reserves are subcategorized as producing or non-producing" (SPE, 1987). This
36 distinction is made at the reservoir level and not at the field level.

- 37
38
- 39 • Any developed reservoir in a developed field that has not produced or has not had
40 sustained production during the past year is considered to contain proved developed
41 non-producing reserves. This category includes reserves contained in non-producing
42 reservoirs, contained reserves behind-pipe, and reservoirs awaiting well workovers or
43 transportation facilities.
 - 44 • Once the first reservoir in a field begins production, the reservoir is considered to
45 contain proved developed producing reserves, and the field is considered on
46 production. If a reservoir had sustained production during the last year, it is considered
47 to contain proved developed producing reserves.

Production represents the proved oil and gas reserves that were extracted from existing reserves.³³

End of the terms in Illustration 1 that are defined under the subheading **Definitions of Resource and Reserve Components and Subcomponents**

Other Definitions

Acquisitions: The volume of proved reserves gained by the purchase of existing fields or properties, from the date of purchase or transfer.

Adjustments: The quantity which preserves an exact annual reserves balance within each State or State subdivision of the following form:

These adjustments are the yearly changes in the published reserve estimates that cannot be attributed to the estimates for other reserve change categories because of the survey and statistical estimation methods employed. For example, variations as a result of changes in the operator frame, different random samples or imputations for missing or unreported reserve changes, could contribute to adjustments.

Basin: The site of accumulation of a large thickness of sediments.³⁴

Bonus Bid: Leases issued in areas known to contain minerals are awarded through a competitive bidding process. A bonus bid, as used in this Statement, represents the cash amount successfully bid to win the rights to a lease.³⁵

Crude oil is a mixture of hydrocarbons that exists in the liquid phase in natural underground reservoirs and remains liquid at atmospheric pressure after passing through surface separating facilities. Crude oil may also include: 1) small amounts of hydrocarbons that exist in the gaseous phase in natural underground reservoirs but are liquid at atmospheric pressure after being recovered from oil well gas in lease separators, and that subsequently are commingled with the **crude oil stream** without being separately measured; and, 2) small amounts of nonhydrocarbons produced with the oil.

Crude Oil Stream: Crude oil produced in a particular field or a collection of crude oils with similar qualities from fields in close proximity, which the petroleum industry usually describes with a specific name, such as West Texas Intermediate.

³³ Adapted from Gas Energy Review, Gas Supply and Demand Committee, July 1995, Vol.23 No. 7.

³⁴ U.S. Geological Survey, Geologic Glossary.

³⁵ Glossary of Mineral Terms, Minerals Revenue Management, Minerals Management Service, U.S. Department of the Interior. ([Glossary of Mineral Terms](#))

Deleted: -----¶
-----¶
¶
Historical Estimates of Proved Reserves¶
¶
Acquisitions: The volume of proved reserves gained by the purchase of existing fields or properties, from the date of purchase or transfer.¶
¶
Adjustments: The quantity which preserves an exact annual reserves balance within each State or State subdivision of the following form.¶
These adjustments are the yearly changes in the published reserve estimates that cannot be attributed to the estimates for other reserve change categories because of the survey and statistical estimation methods employed. For example, variations as a result of changes in the operator frame, different random samples or imputations for missing or unreported reserve changes, could contribute to adjustments.¶
¶
Change from Prior Year: the net change between proved reserves reported for the prior reporting period and proved reserves reported for the current reporting period.¶
¶
Estimated Production: The volumes of oil and gas that are extracted or withdrawn from reservoirs during the report year. ¶
¶
Extensions: The reserves credited to a reservoir because of enlargement of its proved area. Normally the ultimate size of newly discovered fields, or newly discovered reservoirs in old fields, is determined by wells drilled in years subsequent to discovery. When such wells add to the proved area of a previously discovered reservoir, the increase in proved reserves is classified as an extension.¶
¶
Net of Sales and Acquisitions: the net change in the quantity of reserve estimates, either positive or negative, as a result of reserves gained through purchase and deducted through sale during the report year.¶
¶
New Field Discoveries: The volumes of proved reserves of crude oil, natural gas and/or natural gas liquids discovered in new fields during the report year.¶

... [5]

Deleted: standard

1 **Dry Gas:** The actual or calculated volumes of natural gas which remain after: 1. The liquefiable
2 hydrocarbon portion has been removed from the gas stream (i.e., gas after lease, field, and/or
3 plant separation) 2. Any volumes of nonhydrocarbon gases have been removed where they
4 occur in sufficient quantity to render the gas unmarketable.

5
6 **Estimated petroleum royalties** means the estimated end-of-period value of the federal
7 government's royalty share of proved oil and gas reserves from federal oil and gas resources.

8
9 **Estimated Production:** The volumes of oil and gas that are extracted or withdrawn from
10 reservoirs during the report year.

11
12 **Estimated Value for Royalty Relief:** Existing statutes authorize the Minerals Management
13 Service (MMS) to grant royalty relief to operators on the production of oil and gas resources
14 from federal oil and gas leases. Royalty relief is the reduction, modification, or elimination of
15 any royalty to operators to promote development, increase production, or encourage production
16 of marginal resources on certain leases or categories of leases. The estimated value for royalty
17 relief is the calculated approximation of royalty relief based on a formula developed by the
18 Department of the Interior.

19
20 **Extensions:** The reserves credited to a reservoir because of enlargement of its proved area.
21 Normally the ultimate size of newly discovered fields, or newly discovered reservoirs in old
22 fields, is determined by wells drilled in years subsequent to discovery. When such wells add to
23 the proved area of a previously discovered reservoir, the increase in proved reserves is
24 classified as an extension.

25
26 **Federal Oil and Gas Resources:** Oil and gas resources over which the federal government
27 may exercise sovereign rights with respect to exploration and exploitation and from which the
28 federal government has the authority to derive revenues for its use. Federal oil and gas
29 resources do not include resources over which the federal government acts as a fiduciary for
30 the benefit of a non-federal party.

31
32 **Federal jurisdiction** is defined under accepted principles of international law. The seaward limit
33 is defined as the farthest of 200 nautical miles seaward of the baseline from which the breadth
34 of the territorial sea is measured or, if the continental shelf can be shown to exceed 200 nautical
35 miles, a distance not greater than a line 100 nautical miles from the 2,500-meter isobath or a
36 line 350 nautical miles from the baseline.

37
38 **Field** is an area consisting of a single reservoir or multiple reservoirs all grouped on, or related
39 to, the same individual geological structural feature and/or stratigraphic condition. There may be
40 two or more reservoirs in a field that are separated vertically by intervening impervious strata or
41 laterally by local geologic barriers, or by both. The area may include one lease, a portion of a
42 lease, or a group of leases with one or more wells that have been approved as producible.

43
44 **First purchase price** is the actual amount paid by the first purchaser for crude oil as it leaves
45 the lease on which it was produced.³⁶ A "first purchase" constitutes a transfer of ownership of

³⁶ EIA-182 Domestic Crude Oil First Purchase Report Instructions.

1 crude oil during or immediately after the physical removal of the crude oil from a production
2 property for the first time.

3
4 **Gas:** A mixture of hydrocarbon compounds and small quantities of various nonhydrocarbons
5 existing in the gaseous phase or in solution with crude oil in natural underground reservoirs at
6 reservoir conditions.

7
8 **Hydrocarbon:** An organic chemical compound of hydrogen and carbon in the gaseous, liquid,
9 or solid phase. The molecular structure of hydrocarbon compounds varies from the simplest
10 (methane, a constituent of natural gas) to the very heavy and very complex.

11
12 **Lease:** "Lease," as used in this [Statement](#), means any contract, profit-share arrangement, joint
13 venture, or other agreement issued or approved by the United States under a mineral leasing
14 law that authorizes exploration for, extraction of, and/or removal of oil or gas.³⁷

15
16 **Lease condensate:** A mixture consisting primarily of pentanes and heavier hydrocarbons which
17 is recovered as a liquid from natural gas in lease separation facilities. This category excludes
18 natural gas plant liquids, such as butane and propane, which are recovered at downstream
19 natural gas processing plants or facilities.

20
21 **Long-term Assumptions:** Assumptions are considered long-term if the underlying event about
22 which the assumption is made will not occur for five years or more. If the event is one of a series
23 of events the entire series should be considered the event and, thus, the payment may
24 commence within one year but would be required to extend at least five years. Otherwise, the
25 asset or liability would be classified as short-term.

26
27 **Marketable Treasury Securities:** Debt securities, including Treasury bills, notes, and bonds,
28 that the U.S. Treasury offers to the public and are traded in the marketplace. Their bid and ask
29 prices are quoted on securities exchange markets.

30
31 **Natural gas plant liquids (NGPLs):** Those hydrocarbons in natural gas that are separated as
32 liquids at natural gas processing plants, fractionating and cycling plants, and, in some instances,
33 field facilities. Lease condensate is excluded. Products obtained include ethane; liquefied
34 petroleum gases (propane, butanes, propane-butane mixtures, ethane-propane mixtures);
35 isopentane; and other small quantities of finished products, such as motor gasoline, special
36 naphthas, jet fuel, kerosene, and distillate fuel oil.

37
38 **Net of Sales and Acquisitions:** the net change in the quantity of reserve estimates, either
39 positive or negative, as a result of reserves gained through purchase and deducted through sale
40 during the report year.

41
42 **New Field Discoveries:** The volumes of proved reserves of crude oil, natural gas and/or
43 natural gas liquids discovered in new fields during the report year.

Deleted: Gravity Bands: The density of oil compared to the density of water, i.e., the specific gravity of the oil. The gravity is measured in degrees by the American Petroleum Institute (API). Oil with a low number is less valuable than with a high number. For example, oil is classified as light, medium or heavy, according to its measured API gravity. Light crude oil is defined as having an API gravity higher than 31.1°API. Medium oil is defined as having an API gravity between 22.3°API and 31.1°API. Heavy oil is defined as having an API gravity below 22.3°API.¶

Deleted: standard

³⁷ 30 U.S.C. §1702 (5).

New Reservoir Discoveries in Old Fields: The volumes of proved reserves of crude oil, natural gas, and/or natural gas liquids discovered during the report year in new reservoir(s) located in old fields.

Oil: A mixture of hydrocarbons that exists in the liquid phase in natural underground reservoirs and remains liquid at atmospheric pressure after passing through surface separating facilities.

Outer Continental Shelf (OCS): The federal Government administers the submerged lands, subsoil, and seabed lying between the seaward extent of the States' jurisdiction and the seaward extent of federal jurisdiction.³⁸

Play: A group of pools that share a common history of hydrocarbon generation, migration, reservoir development, and entrapment.³⁹

Pool: A discovered or undiscovered accumulation of hydrocarbons, typically within a single stratigraphic interval.⁴⁰

Present Value: The value of future cash flows discounted to the present at a certain interest rate (such as the reporting entity's cost of capital), assuming compound interest.

Proved Reserves: The total quantity of proved reserves which is calculated by adding the quantity of reserves reported as revisions and adjustment, net of sales and acquisitions, total recoveries and deducting estimated production during the report year.

Regional Estimated Petroleum Royalties: Regional estimated petroleum royalties means the estimated end-of-period value of the federal government's royalty share of proved oil and gas reserves from federal oil and gas resources in each region.

Rent: Rent, as used in this Statement, are annual payments, normally a fixed dollar amount per acre, required to preserve the rights to a lease while the lease is not in production. A rent schedule is established at the time a lease is issued.⁴¹

Deleted: standard

Reservoir: A porous and permeable underground formation containing an individual and separate natural accumulation of producible hydrocarbons (oil and/or gas) which is confined by impermeable rock or water barriers and is characterized by a single natural pressure system.⁴²

Revisions: Changes to prior year-end proved reserves estimates, either positive or negative, resulting from new information other than an increase in proved acreage (extension). Revisions include increases of proved reserves associated with the installation of improved recovery techniques or equipment. They also include correction of prior report year arithmetical or clerical

Deleted: , Minerals Revenue Management, Mineral Management Service, U.S. Department of the Interior.

Deleted: Glossary of Mineral Terms, Minerals Revenue Management, Minerals Management Service, U.S. Department of the Interior.

Deleted: Glossary of Mineral Terms, Minerals Revenue Management, Minerals Management Service, U.S. Department of the Interior

³⁸ Glossary of Mineral Terms.

³⁹ Ibid.

⁴⁰ Ibid.

⁴¹ Ibid.

⁴² Ibid.

1 errors and adjustments to prior year-end production volumes to the extent that these alter
2 reported prior year reserves estimates.

3
4 **Revisions and Adjustments:** the net change in the quantity of reserve estimates, either
5 positive or negative, as a result of adding changes reported as revisions and adjustments during
6 the report year.

7
8 **Royalty:** Royalty, as used in this Statement, means any payment based on the value or
9 volume of production which is due to the United States on production of oil or gas from the
10 Outer Continental Shelf or federal lands, or any minimum royalty owed to the United States
11 under any provision of a lease.⁴³

Deleted: standard

12
13 **Royalty-in-kind:** A program operated under the provisions of the Mineral Leasing Act of 1920
14 and the Outer Continental Shelf Lands Act of 1953. The federal government, as lessor, may
15 take part or all of its oil and gas royalties "in kind" (a volume of the commodity) as opposed to "in
16 value" (money). Under the oil royalty-in-kind program, the government sells oil at fair market
17 value to eligible refiners who do not have access to an adequate supply of crude oil at equitable
18 prices. The Minerals Management Service conducted a gas royalty-in-kind pilot program in
19 1995, entering into contracts to sell selected Gulf of Mexico natural gas by competitive bid to
20 gas marketers. Two additional oil and gas pilot programs began in 1998, and a third gas pilot
21 program began in 1999.⁴⁴

22
23 **Royalty rate:** A proportionate interest in the production value of mineral deposits due the
24 lessor from the lessee in accordance with a lease agreement.

25
26 **Sales:** The volume of proved reserves deducted from an operator's total reserves when selling
27 an existing field or property, during the calendar year.

28
29 **Sales Value:** The proceeds received for the sale of a product. Sales value is calculated by
30 multiplying the sales volume by unit price.

31
32 **Sales Volume:** The volume, or quantity, of the product that is sold. The sales volume is
33 measured in thousand cubic feet (mcf) for gas and in barrels (bbl) for oil.

34
35 **States' jurisdiction** is defined as follows:

- 36 • Texas and the Gulf coast of Florida are extended 3 marine leagues (9 nautical miles)
37 seaward from the baseline from which the breadth of the territorial sea is measured.
- 38 • Louisiana is extended 3 imperial nautical miles (imperial nautical mile = 6080.2 feet)
39 seaward of the baseline from which the breadth of the territorial sea is measured.
- 40 • All other States' seaward limits are extended 3 nautical miles (approximately 3.3 statute
41 miles) seaward of the baseline from which the breadth of the territorial sea is measured.
42

⁴³ Adapted from 30 U.S.C. § 1702 (14).

⁴⁴ [Glossary of Mineral Terms.](#)

1 | **Technically recoverable resources:** For purposes of this Statement, the term used to describe
2 | the total quantity of undiscovered recoverable resources and unproved reserves. Proved
3 | reserves are not included in the estimated quantity of technically recoverable resources.

Deleted: standard

4 |
5 | **Total Discoveries:** the total quantity of additional discovered reserves which is calculated by
6 | adding the quantity of reserves reported as a result of extensions, the quantity of reserves
7 | reported as a result of new field discoveries, and the quantity of reserves reported as a result of
8 | new discoveries in old fields during the report year.

9 |
10 | **Wellhead price** is the value of the purchased natural gas at the mouth of the well. In general,
11 | the wellhead price is considered to be the sales price obtainable from a third party in an arm's
12 | length transaction. Posted prices, requested prices, or prices as defined by lease agreements,
13 | contracts, or tax regulations should be used where applicable.⁴⁵

⁴⁵ Energy Information Administration Glossary, http://www.eia.doe.gov/glossary/glossary_w.htm.

FASAB Board Members

Tom L. Allen, Chair
Robert F. Dacey
John A. Farrell
Norwood J. Jackson, Jr.
James M. Patton
Robert N. Reid
Alan H. Schumacher
Harold I. Steinberg
Danny Werfel

FASAB Staff

Wendy M. Payne, Executive Director

Project Staff

Julia Ranagan

Federal Accounting Standards Advisory Board
441 G Street NW, Suite 6814
Mail Stop 6K17V
Washington, DC 20548
Telephone 202-512-7350
FAX 202-512-7366
www.fasab.gov

Tab F-2

Appendix 1 – Issue Papers

[This page intentionally left blank.]

Issue Paper No. 1: Component Entity RSI

December 2008 Draft ED Requirements

The December 2008 draft of the revised exposure draft (ED) on *Accounting for Federal Oil and Gas Resources* contained the following proposed component entity RSI disclosure requirements that were carried forward from the May 2007 ED, revised only to exclude reference to the separate components of oil and gas (oil and lease condensate, NGPL, and gas) and update the paragraph numbers.

Component Entity Required Supplementary Information (RSI)

44. The component entity responsible for reporting the federal government's estimated petroleum royalties on its balance sheet shall provide the following as RSI:
 - a. A narrative describing and a display showing the most current and complete information available for **technically recoverable resources**. The information shall include the estimated quantity of offshore technically recoverable resources from federal oil and gas resources, the estimated quantity of onshore technically recoverable resources from federal oil and gas resources, the as-of-date for the information being presented, and a brief explanation of changes to the information from the previous reporting period.
 - b. A narrative describing and a display showing the following information for each region that was identified for use in calculating the federal government's total estimated petroleum royalties:
 - i. The **sales volume**, the sales value, the royalty revenue earned, and the **estimated value for royalty relief** produced from federal oil and gas resources for the reporting period shall be added together in each region and reported.
45. A narrative describing and a display showing the following historical information about proved oil and gas reserves from federal leases for each of the preceding ten calendar years: adjustments; net revisions; revisions and adjustments; net of sales and acquisitions; extensions; new field discoveries; new **reservoir** discoveries in old fields; total discoveries; estimated production; proved reserves; and change from prior year. Definitions for these terms are contained in the Glossary under the subheading "**Historical Estimates of Proved Reserves.**"

DOI Response to Current Draft ED Requirements

Requirement 44b – Table 1

In its comment letter, DOI stated that (with regard to 44b above):

"The Department has ascertained that the information provided in Table 1 on page 68 and 69 of the ED can be readily produced, but it is critical to clarify and specify exactly what this data includes. As discussed at length in the field test questionnaires, we believe that it must be based upon the royalty reporting lines received and accepted for the preceding twelve sales months for which royalty production data is available at fiscal year end. This

would be the only way to ensure that prior period adjustments to previous royalty reporting are not included in current period statistics.”

In response to question 6 on the present value (PV) field test questionnaire, the field test team stated that:

“In addition to current royalty amounts, MMS records earned revenue in the current period for the sum of both positive and negative amounts resulting from upward or downward adjustments to prior royalty reporting, related to previous months when the commodity had been either sold or removed from the lease (**sales months**). This is a standard business process in oil and gas industry reporting, resulting from the receipt of subsequent information related to previous reporting periods that was unknown when the compulsory reporting was legally due, such as revised pipeline statements. These adjustments frequently cross monthly, quarterly, and fiscal year boundaries, can be large amounts, and are routine.

If depletion expense is linked across the board with overall revenue earned in the current year, then it must be understood that it would be at least partially based on revenue earned in the current year that is related to adjustments to prior periods falling outside the fiscal year. Therefore, the asset would be depleted in the current year based upon activity that does not actually reflect true depletion in the actual year.

If depletion expense were alternatively based upon revenue earned for oil & gas royalty reports related to current year production only, to most closely reflect the actual asset depletion in the current year, it would be applicable to only the **sales months** falling within the fiscal year. This would exclude prior period adjustments to royalty reporting that would be deemed unrelated to depletion in the current year.

However, complete royalty reporting covering production in the current fiscal year measured at 9/30 can only be ascertained through August, which covers actual reported royalty production through June (for which delayed reporting would not be due until August if a paid estimate were in place). In other words, only 9 months of complete sales month (production) data within a given fiscal year are available at 9/30 if basing ‘revenue earned’ and depletion expense only on current fiscal year sales months; October through June. Clearly, this would not present a complete picture of current year asset depletion, because it would not even include a full 12 months of royalty reporting.

In response to question 7 on the present value field test questionnaire, the field test team stated that:

“In order to exclude adjustments to prior period reporting not attributable to depletion in the current year, and to exclude potentially unrelated estimates from the depletion calculations, **the recommended method is to record depletion based upon royalty reporting lines received and accepted for the preceding 12 sales months available at fiscal year end; July through June (received through August, fully available in September). Revenue earned would not be a perfect match in the fiscal year, but in this case it should not, because depletion in the current year should not be linked to prior adjustments not related to the current year.** To do otherwise would *include* prior period adjustments not related to depletion in the year, and would involve complex and extensive inclusion of current year estimates that are potentially unrelated to depletion and also include prior period adjustments. **This method would likely yield a more accurate picture of current asset depletion over a year span. This method would also provide the ability, with sophisticated queries and system reports, to derive the detailed information the ED requires from actual royalty reports, such as commodity type, Region, onshore vs. offshore and other necessary details.**”

Requirements 45 and 44a – Tables 2 and 3

In its comment letter, DOI stated that (with regard to 45 and 44a above):

“The information presented in Table 2 on pages 70 and 71 of the ED is derived from published EIA data that is nationwide in scope, covering both federal and non-federal ownership. More updated or current data presented in the Table specific to federal domain estimated proved reserves is not available, and could not be provided at the report date. As discussed in the valuation process above, EIA nationwide data were obtained and a rough estimation methodology was developed to derive estimated proved reserves under federal domain. Additional offshore calculations were required as well. The additional information required in the ED for RSI disclosure, such as federal domain technically recoverable resources, onshore and offshore, and historical 10-year information on federal domain estimated proved reserves could only be provided by EIA. If the Board intends that estimated calculations be produced, we request clarification. However, such things as net revisions, extensions, new field discoveries, etc. could not be reasonably ascertained. Readers of federal financial information should be referred to EIA published statistics for that information.”

In response to question 8 on the present value field test questionnaire, the field test team stated that:

“The information required to be provided in the ED is not available, and so **could not be provided by the MMS. This is information that can only be gathered and provided by the EIA.** As discussed in the valuation process above, MMS had to obtain EIA nationwide data and develop a rough estimation methodology to attempt to arrive at an estimate of the estimated proved reserves under federal domain. The additional information required in the ED for RSI disclosure, such as federal domain technically recoverable resources, onshore and offshore, and historical 10-year information on federal domain estimated proved reserves could only be provided by EIA. If the Board intends that estimated calculations be produced, we request that be clarified. However, such things as net revisions, extensions, new field discoveries, etc. could not be reasonably ascertained.”

FASAB Staff Analysis and Recommendation

The following staff recommendations are based on staff’s interpretation of the board’s intent in the original ED, the type of information that is currently available, the field test team’s responses to staff’s additional questions at Attachment A, and DOI’s as well as other respondents’ comments to the May 2007 ED.

Requirement 44b – Table 1

The DOI field test team has recommended that the information presented in Table 1 be based upon the royalty reporting lines received and accepted for the preceding twelve sales months for which royalty production data is available at fiscal year end. This is the same basis upon which the DOI field test team recommended that depletion expense be recognized.

As noted in Issue Paper No. 4: Depletion Expense, FASAB staff believes that the depletion approach in the ED was not devised to show the “true” effect on the asset during the period since the quantity gets adjusted again at year-end as part of the revaluation. Rather, the depletion approach was an attempt to ensure that the only bottom line effect on MMS’ statement of net cost was the net gain / loss that resulted from quantity and value differences from one year to the next. In other words, the depletion approach in the ED is to “match” depletion

expense with revenue recognition. Therefore, staff believes that the information presented in Table 1 should be based upon royalty revenue earned in the fiscal year and **not** on “the royalty reporting lines received and accepted for the preceding twelve sales months for which royalty production data is available at fiscal year end” as recommended by the DOI field test team.

Staff recommends that the board retain the proposed requirements in paragraph 44b of the current draft ED.

Requirements 45 and 44a – Tables 2 and 3

Illustrative Table 2 on page 71 of the May 2007 ED was derived from a table in the Energy Information Administration’s (EIA) annual “U.S. Crude Oil, Natural Gas, and Natural Gas Liquids Reserves Report (Annual Report).” See Table 1 from the 2006 Annual Report on page 5. However, this table is based on nationwide data and is not available for proved reserves under federal domain only.

Illustrative Table 3 on page 73 of the May 2007 ED was derived directly from a table in EIA’s Annual Report. This table reported federal resources separately from non-federal. See Table G1 from the 2005 Annual Report on page 6. However, EIA did not report the federal percentage of technically recoverable resources in the 2006 Annual Report (see Table G1 from the 2006 Annual Report on page 7).¹

FASAB staff has been unsuccessful in its numerous attempts to reach EIA personnel to discuss reporting of resources under federal domain. As such, it is not known whether this information will ever be provided.

Since the valuation methodology proposed by the field test team is a high-level estimate based on nationwide proved reserves data, any efforts to provide the information requested in pars. 44a and 45 would be a SWAG and would most likely not provide any meaningful, reliable, or consistent numbers for financial statement users or management.

The majority of respondents to the May 2007 draft ED agreed that the numerous disclosures proposed in the ED appeared excessive and might not pass a cost/benefit test. None of the respondents argued to keep the required disclosures and RSI.

Staff recommends that the board delete the proposed requirements in paragraphs 44a and 45 and replace them with requirements to present the major assumptions used to calculate the value of the federal government’s estimated petroleum royalties, explain the changes in the estimate from one year to the next, and reference the source reports used.

44.43. The component entity responsible for reporting the federal government’s estimated petroleum royalties on its balance sheet shall provide the following as RSI:

- a. ~~A narrative describing and a display showing the most current and complete information available for technically recoverable resources. The information shall include the estimated quantity of~~

¹ The full 2007 Annual Report is not yet available.

~~offshore technically recoverable resources from federal oil and gas resources, the estimated quantity of onshore technically recoverable resources from federal oil and gas resources, the as-of-date for the information being presented, and a brief explanation of changes to the information from the previous reporting period.~~

A narrative describing the estimation methodology used to calculate the value of the federal government's estimated petroleum royalties. At a minimum, the narrative explanation should include a "plain English" explanation of the measurement method (e.g., present value) and the significant assumptions incorporated into the estimate (e.g., discount rates used to calculate present value, production decline curve, portion of proved reserves under federal lands, future oil and gas prices, inflation rates, etc).

- b. An explanation of the significant components of the change in estimated petroleum royalties from one year to the next, the amounts associated with each type of change, and the reasons for the changes. The reasons should be explained as briefly as possible without detracting from understanding. Significant components of the change in estimated petroleum royalties include, but are not limited to, changes in quantity, price, royalty rates, discount rates, and inflation rates.
- c. A reference to the source reports used to calculate the value of the federal government's estimated petroleum royalties.
- d. A narrative describing and a display showing the following information for each region that was identified for use in calculating the federal government's total estimated petroleum royalties:
 - i. ~~The sales volume, the sales value, the royalty revenue earned, and the estimated value for royalty relief produced from federal oil and gas resources for the reporting period. To the extent that regional information is available, provide the information for shall be added together in each region and reported.~~

45. ~~A narrative describing and a display showing the following historical information about proved oil and gas reserves from federal leases for each of the preceding ten calendar years: adjustments; net revisions; revisions and adjustments; net of sales and acquisitions; extensions; new field discoveries; new reservoir discoveries in old fields; total discoveries; estimated production; proved reserves; and change from prior year. Definitions for these terms are contained in the Glossary under the subheading "Historical Estimates of Proved Reserves."~~

2006 Annual Report

Table 1. Total U.S. Proved Reserves of Crude Oil, Dry Natural Gas, and Natural Gas Liquids, 1996-2006

Year	Adjustments (1)	Net Revisions (2)	Revisions ^a and Adjustments (3)	Net of Sales ^b and Acquisitions (4)	Extensions (5)	New Field Discoveries (6)	New Reservoir Discoveries in Old Fields (7)	Total ^c Discoveries (8)	Estimated Production (9)	Proved ^d Reserves 12/31 (10)	Change from Prior Year (11)
Crude Oil (million barrels of 42 U.S. gallons)											
1996	175	737	912	NA	543	243	141	927	2,173	22,017	-334
1997	520	914	1,434	NA	477	637	119	1,233	2,138	22,546	+529
1998	-638	518	-120	NA	327	152	120	599	1,991	21,034	-1,512
1999	139	1,819	1,958	NA	259	321	145	725	1,952	21,765	+731
2000	143	746	889	-20	766	276	249	1,291	1,880	22,045	+280
2001	-4	-158	-162	-87	866	1,407	292	2,565	1,915	22,446	+401
2002	416	720	1,136	24	492	300	154	946	1,875	22,677	+231
2003	163	94	257	-398	426	705	101	1,232	1,877	21,891	-786
2004	74	420	494	23	617	33	132	782	1,819	21,371	-520
2005	221	569	790	278	805	205	41	1,051	1,733	21,757	+386
2006	94	2	96	194	504	30	43	577	1,652	20,972	-785
Dry Natural Gas (billion cubic feet, 14.73 psia, 60° Fahrenheit)											
1996	3,785	4,086	7,871	NA	7,757	1,451	3,110	12,318	18,861	166,474	+1,328
1997	-590	4,902	4,312	NA	10,585	2,681	2,382	15,648	19,211	167,223	+749
1998	-1,635	5,740	4,105	NA	8,197	1,074	2,162	11,433	18,720	164,041	-3,182
1999	982	10,504	11,486	NA	7,043	1,568	2,196	10,807	18,928	167,406	+3,365
2000	-891	6,962	6,071	4,031	14,787	1,983	2,368	19,138	19,219	177,427	+10,021
2001	2,742	-2,318	424	2,630	16,380	3,578	2,800	22,758	19,779	183,460	+6,033
2002	3,727	937	4,664	380	14,769	1,332	1,694	17,795	19,353	186,946	+3,486
2003	2,841	-1,638	1,203	1,034	16,454	1,222	1,610	19,286	19,425	189,044	+2,098
2004	-114	744	630	1,844	18,198	759	1,206	20,163	19,168	192,513	+3,469
2005	1,887	2,699	4,586	2,544	21,050	942	1,208	23,200	18,458	204,385	+11,872
2006	743	-1,836	-1,093	2,996	21,778	409	1,155	23,342	18,545	211,085	+6,700
Natural Gas Liquids (million barrels of 42 U.S. gallons)											
1996	474	175	649	NA	451	65	109	625	850	7,823	+424
1997	-15	289	274	NA	535	114	90	739	864	7,973	+150
1998	-361	208	-153	NA	383	66	88	537	833	7,524	-449
1999	99	727	826	NA	313	51	88	452	896	7,906	+382
2000	-83	459	376	145	645	92	102	839	921	8,345	+439
2001	-429	-132	-561	102	717	138	142	997	890	7,993	-352
2002	62	31	93	54	612	48	78	738	884	7,994	+1
2003	-338	-161	-499	30	629	35	72	736	802	7,459	-535
2004	273	97	370	112	734	26	54	814	827	7,928	+469
2005	-89	21	-68	156	863	32	42	937	788	8,165	+237
2006	173	-165	8	117	924	16	53	993	811	8,472	+307

^aRevisions and adjustments = Col. 1 + Col. 2.

^bNet of sales and acquisitions = acquisitions - sales.

^cTotal discoveries = Col. 5 + Col. 6 + Col. 7.

^dProved reserves = Col. 10 from prior year + Col. 3 + Col. 4 + Col. 8 - Col. 9.

NA=Not available.

Notes: Old means discovered in a prior year. New means discovered during the report year. The production estimates in this table are based on data reported on Form EIA-23, "Annual Survey of Domestic Oil and Gas Reserves" and Form EIA-64A, "Annual Report of the Origin of Natural Gas Liquids Production." They may differ from the official EIA production data for crude oil, natural gas, and natural gas liquids for 2006 contained in the *Petroleum Supply Annual 2006*, DOE/EIA-0340(06) and the *Natural Gas Annual 2006*, DOE/EIA-0131(06).

2005 Annual Report

Table G1. Mean Estimates of Technically Recoverable Oil and Gas Resources by Deposit Type and Location

Area	Jurisdiction	Crude Oil ^a (billion barrels)	Natural Gas (Dry) (trillion cubic feet)	Natural Gas Liquids (billion barrels)
<u>Undiscovered Conventionally Reservoired Fields</u>				
Alaska Onshore + State Offshore	Federal	3.75	33.97	0.54
Alaska Onshore + State Offshore	Other	4.68	95.37	0.61
Alaska Federal Offshore	Federal	24.90	122.60	0.00
Lower 48 States Onshore + State Offshore	Federal	3.79	23.97	1.26
Lower 48 States Onshore + State Offshore	Other	17.83	166.41	5.64
Lower 48 States Federal Offshore	Federal	50.10	239.60	0.00
Alaska Subtotal		33.33	251.94	1.15
Alaska Percentage Federal		86.0%	62.1%	47.0%
Lower 48 States Subtotal		71.72	429.98	6.90
Lower 48 States Percentage Federal		75.1%	61.3%	18.3%
Technically Recoverable Resources in U.S. Undiscovered Conventionally Reservoired Fields				
Percentage Federal		78.6%	61.6%	22.4%
<u>Ultimate Recovery Appreciation</u>				
U.S. Onshore + State Offshore	Federal	14.33	118.70	4.94
U.S. Onshore + State Offshore	Other	45.67	203.30	8.46
U.S. Federal Offshore	Federal	7.70	68.00	0.00
Technically Recoverable Resources in U.S. from Ultimate Recovery Appreciation in Discovered Conventionally Reservoired Fields				
U.S. Percentage Federal		32.5%	47.9%	36.9%
<u>Continuous Type Deposits</u>				
Non-coal bed	Federal	0.32	127.08	1.45
Non-coal bed	Other	1.75	181.72	0.67
Coal bed	Federal	0.00	16.08	0.00
Coal bed	Other	0.00	33.83	0.00
Non-coal bed Subtotal		2.07	308.80	2.12
Non-coal bed Percentage Federal		15.5%	41.2%	68.4%
Coal bed Subtotal		0.00	49.91	0.00
Coal bed Percentage Federal		0.0%	32.2%	0.0%
Technically Recoverable Resources in U.S. from Continuous Type Deposits				
Continuous Type Percentage Federal		15.5%	39.9%	68.4%
<u>U.S. Totals All Sources</u>				
U.S. Onshore + State Offshore	Federal	22.19	319.80	8.19
U.S. Onshore + State Offshore	Other	69.93	680.63	15.38
Federal Offshore	Federal	82.70	430.20	0.00
Federal Subtotal		104.89	750.00	8.19
U.S. Technically Recoverable Resources				
Percentage Federal		60.0%	52.4%	34.7%

Notes:

Proved Reserves are not included in these estimates.

Federal Onshore excludes Indian and Native lands even when Federally managed in trust.

Zero (0) indicates either that none exists in this area or that no estimate of this resource has been made for this area.

2006 Annual Report

Table G1. Mean Estimates of Technically Recoverable Oil and Gas Resources by Deposit Type and Location

Area	Crude Oil (billion barrels)	Natural Gas (Dry) (trillion cubic feet)	Natural Gas Liquids (billion barrels)
Undiscovered Conventionally Reservoired Fields			
Alaska Onshore + State Offshore	26.04	126.75	2.23
Alaska Federal Offshore	26.61 ^a	132.06	0.00 ^a
Lower 48 States Onshore + State Offshore	18.24	178.21	5.56
Lower 48 States Federal Offshore	59.27 ^a	287.82	0.00 ^a
Alaska Subtotal	52.65	258.81	2.23
Lower 48 States Subtotal	77.51	466.03	5.56
Technically Recoverable Resources in U.S. Undiscovered Conventionally Reservoired Fields	130.16	724.84	7.79
Ultimate Recovery Appreciation			
Alaska Onshore + State Offshore	6.96	12.30	0.41
Lower 48 States Onshore + State Offshore	31.70	442.50	17.85
U.S. Federal Offshore	6.88 ^a	30.91	0.00 ^a
Technically Recoverable Resources in U.S. from Ultimate Recovery Appreciation in Discovered Conventionally Reservoired Fields	45.54	485.71	18.26
Continuous Type Deposits			
Alaska Non-coal bed	0.00	0.00	0.00
Lower 48 States Non-coal bed	2.13	236.89	3.80
Alaska Coal bed	0.00	18.06	0.00
Lower 48 States Coal bed	0.00	67.32	0.00
Non-coal bed Subtotal	2.13	236.89	3.80
Coal bed Subtotal	0.00	85.38	0.00
Technically Recoverable Resources in U.S. from Continuous Type Deposits	2.13	322.27	3.80
U.S. Totals All Sources			
U.S. Onshore + State Offshore	85.07	1,082.03	29.85
Federal Offshore	92.76 ^a	450.79	0.00 ^a
U.S. Technically Recoverable Resources	177.83	1,532.82	29.85

^a The MMS jointly reports natural gas liquids with crude oil for the Federal Offshore.

Additional Notes: Proved Reserves are excluded from these estimates as are undiscovered oil resources in tar deposits and oil shales, and undiscovered gas resources in geopressed brines and gas hydrates.

Zero (0) indicates either that none exists in this area or that no estimate of this resource has been made for this area, or in the instance of Federal offshore natural gas liquids resources that they are jointly reported with crude oil.

Federal Onshore excludes Indian and Native lands even when Federally managed in trust.

Federal Offshore indicates MMS estimates for Federal Offshore jurisdictions (Outer Continental Shelf and deeper water areas seaward of State Offshore).

Data Sources: National Oil and Gas Resource Assessment Team, 2007 Assessment Updates, United States Geological Survey, Washington DC, December 2007 at <http://energy.cr.usgs.gov/oilgas/noga/ass_updates.html>

Resource Evaluation Division, Assessment of Undiscovered Technically Recoverable Oil and Gas Resources of the Nation's Outer Continental Shelf, 2006, MMS Fact Sheet RED-2006-01b, Minerals Management Service, Washington, DC, February 2006 at <<http://www.mms.gov/revaldiv/PDFs/2006NationalAssessmentBrochure.pdf>>.

The ultimate recovery appreciation estimates for Alaska and the Lower 48 States Onshore Plus State Waters were developed by the Reserves and Production Division, Office of Oil and Gas, Energy Information Administration, based on data available as of year-end 2006.

Clarifying Questions from FASAB Staff to DOI Field Test Team

In forming a recommendation to address the proposed component entity RSI requirements, staff posed the following questions to the DOI Field Test Team. Responses from the team are noted below each question.

Requirement 44b – Table 1

Question 1: If the adjustments related to prior periods are “routine” and it is “a standard business process in oil and gas industry reporting” to record them in the current period, why should they be excluded from current period royalty reporting?

DOI Field Test Team Response: We do not propose that reported royalty adjustments related to prior periods be excluded from current period royalty reporting or revenue, and they are not. But they are recommended by the field test team to be excluded from the depletion basis, in order to most accurately capture and report on the best estimate of current depletion, without including potentially large prior period adjustments (or other significant estimates) in current period depletion. Depletion would not match earned revenue 1 for 1 in a fiscal year.

Question 2: If the adjustments should definitely be excluded from current period royalty reporting, does DOI not have the capability to query the earned revenue ledger and exclude adjustments to prior periods through the use of a particular field? It would seem that there would be a field or code or budget reference that would denote prior period. Please explain why this capability does not exist or could not be created within the system.

DOI Field Test Team Response: MMS has the ability to query **royalty reporting lines received and accepted for the preceding 12 sales months available at fiscal year end; July through June (received through August, fully available in September).** This would effectively screen out prior period adjustments and other estimates.

Question 3: If the answer to question two indicates that such a query is not possible, would DOI agree with the following edit to the current requirement (pending approval by the board)?

- b. A narrative describing and a display showing the following information for each region that was identified for use in calculating the federal government’s total estimated petroleum royalties:
 - i. The sales volume, the sales value, the royalty revenue earned, and the estimated value for royalty relief produced from federal oil and gas resources for the ~~reporting period~~ royalty reporting lines received and accepted for the preceding twelve sales months for which royalty data is available at fiscal year-end shall be added together in each region and reported.

DOI Field Test Team Response: Not as presented. Note that if using the PV method proposed by the field test team, then this disclosure does not reflect the basis for the calculations for the federal government’s total estimated petroleum royalties that the below paragraph refers to. That would only have been true if following the old methodology. Please refer to the field test team’s PV Method, page 30, for a description of the basis for calculating the federal government’s total estimated petroleum royalties. Offshore starts with EIA quantity; Onshore with EIA quantity

modified to estimated Federal share, both then compute using the PV method. Our previous comments indicated that any component entity RSI disclosure would best be as flexible as the standard itself, to reflect the method and basis used to calculate estimated petroleum royalties. It may be that even descriptive text could be sufficient. However with that said, this information could be produced and would (with the below caveat) be the general basis for overall depletion.

- b. A narrative describing and a display showing the following information for each region that was identified for use in calculating the federal government's total estimated petroleum royalties:
 - i. The sales volume, the sales value, the royalty revenue earned, and the estimated value for royalty relief produced from federal oil and gas resources for the ~~reporting period~~ royalty reporting lines received and accepted for the preceding twelve sales months for which royalty production data is available at fiscal year-end. **These** shall be added together in each region and reported.

Question 4: If the above edit is made, how would the adjustments to prior periods be reflected? What happens to comparability between periods if the adjustments are material, which they must be to warrant concern? If the adjustments are material and should not be reflected in current year royalty revenue, don't the auditors require them to be reported as prior period adjustments?

DOI Field Test Team Response: The reported royalty adjustments related to prior periods are always included in current period royalty revenue, regardless if they are prior period adjustments. No change is proposed.

Question 5: If the above edit is made, would the resulting table be formatted differently than the illustrative Table 1 on page 69 of the May 2007 ED?

DOI Field Test Team Response: The data could be presented pretty much the way it is displayed, but again it does not currently reflect the basis expected to be used to calculate the federal share of estimated petroleum royalties. But it would (presumably) be the basis for depletion. Headers and FY indicator would need to be revised.

Requirements 45 and 44a – Tables 2 and 3

Question 6: Have you received any indication from EIA that they would be reporting on proved reserves and technically recoverable resources under federal domain at any point in the future?

DOI Field Test Team Response: No, we have not.

Question 7: If the board decides to delete the requirements in pars. 44a and 45, would there be any value in having the component entity financial report refer to the nationwide information reported in EIA's Annual Report?

DOI Field Test Team Response: A link that could lead a reader to the authoritative EIA source data could be beneficial, but to require the component entity to reproduce verbatim that same EIA information seems redundant, especially since it will be stale dated and not reflect the adjustments made by the component entity using the PV method to account for increases and depletion from the EIA report date. And of course, it would not reflect just the Federal portions.

Question 8: Are there any other disclosures that DOI believes would be useful information and should be required as a note disclosure or RSI?

DOI Field Test Team Response: Not at this time.

Responses to the above staff questions were received from Kelly West, MMS Field Test Team Representative.

[This page intentionally left blank.]

Issue Paper No. 2: Fiduciary Reporting Requirements

December 2008 Draft ED Requirements

The December 2008 draft of the revised exposure draft (ED) on *Accounting for Federal Oil and Gas Resources* contained the following proposed fiduciary reporting disclosure requirements that were carried forward from the May 2007 ED.

Disclosure Requirements for Fiduciary Oil and Gas Resources

48. Fiduciary activities are defined in SFFAS 31, *Accounting for Fiduciary Activities*. Information consistent with the requirements of paragraphs 17 through 41 of this document shall be presented as an integral part of the fiduciary activities Schedules of Fiduciary Activity and Net Assets. No additional disclosures or RSI are required by this standard.

DOI Response to Current Draft ED Requirements

In its comment letter, DOI stated that:

“The Department has verified that currently, EIA does not publish numbers related to proved reserves on Indian lands. Further, the Department only receives a small portion of royalties related to Indian leases, which are disbursed at once to OST for subsequent funds management and distribution to beneficiaries. Accordingly, there is not a verifiable data source from which the Department could estimate an asset value. While estimates can always be developed, the validity of the data could likely be proved to be incorrect, and would be a very broad estimate at best.

We believe it would not be cost-beneficial to require such disclosures relating to fiduciary assets, liabilities, and related inflows and outflows. We explain the basis for our belief below.

First, the FASAB made it clear in a letter dated October 5, 2006, that disaggregated financial information was not required to be presented in a fiduciary note disclosure. Specifically, the Board stated:

“In developing Federal accounting standards, among FASAB’s responsibilities is to support cost effective implementation of its standards. To this end, FASAB considers alternative approaches so that a standard’s demand on resources is balanced against the benefits to be gained from the standard. In the particular case of Indian Trust funds, the Board believes the costs to implement proposed SFFAS 31 by developing accruals for receivables at the beneficiary ownership level, as some have suggested, would greatly outweigh the benefits of reporting fiduciary activities conducted by DOI (in the event that SFFAS 31 were to be finalized). The Board did not intend proposed SFFAS 31 to establish a requirement for such highly disaggregated financial reports.

Instead, neither existing standards nor proposed SFFAS 31 require disaggregated financial information to be presented in a note disclosure. To this end, the accrual of fiduciary activities should be implemented as a single aggregate accrual that supports information presented in the schedule of net assets and fiduciary activity in a note to the Department’s financial statements.”

Unfortunately, this Exposure draft would require just that; disaggregated accrual and asset information. Per paragraph 34, specific information regarding estimates of reserves, and inflows and outflows, would require research down to the lease level in order to determine

the split between tribal and individual Indian ownership. Additionally, further analysis would be necessary to distinguish between leases on tribal land where the payments are made directly to the tribal entity and do not flow through the U.S. government. This would defeat the purpose of a single aggregate accrual and be very costly to implement as well as requiring an information system to obtain and track this data.

Secondly, there are many components to Indian trust assets and activities. Required disclosure of oil and gas assets as well as the inflows and outflows would put an undeserved emphasis on this activity in the note disclosure, especially since oil and gas revenues typically encompass only approximately 25% of revenues (similar to farming and grazing, forestry, and land sales). With a number of non-monetary assets held by Indian and tribal beneficiaries, such as land, timber, coal, and other minerals, disclosure of estimated values of oil and gas assets could lead to questions regarding land valuation as well as other non-monetary asset valuations mentioned above. If we are showing oil and gas asset valuation, why are we not showing land asset valuation, or other asset valuations, etc? It creates a dichotomy between oil and gas and other non-monetary trust assets.

Where will additional disclosure requirements end with respect to fiduciary note disclosure? We request removal of paragraph 34 as unnecessary, costly, and in direct conflict with Board issued guidance and the intent of SFFAS 31."

Comments from Respondents to May 2007 ED

Question 5a: Do you believe it is cost-beneficial to require disclosure of the value of estimated fiduciary petroleum royalty assets, liabilities, and related inflows and outflows? Please explain the basis for your beliefs.

Yes, Supportive of Fiduciary Asset Disclosures (Amount / Level TBD)

Comment Letter # 3, Association of Government Accountants Financial Management Standards Board

We believe that accounting standards should be consistent. Based on that premise, the disclosure for fiduciary petroleum royalty assets should be disclosed. The amount and/or level of disclosure could be made after considering (1) cost of getting that information versus its usefulness and (2) the overall "additional" amount of information and disclosure provided by the proposed standard. We also think it is also important to report assets held for the benefit of Indian tribes and individual Indians, particularly in light of difficulties in such reporting related to other Indian assets.

No, Not Supportive of Fiduciary Asset Disclosures

Comment Letter # 4, Office of the Under Secretary of Defense, Department of Defense

We have not performed a cost benefit analysis to support a response to this question. However, reference question 3 above, the cost of the information appears to outweigh the benefit.

[Response to question 3: No. RSI should not extend to the Regional breakdowns exemplified in Table 1. This information does not appear relevant to the Stewardship Objective of determining whether the government's financial position has improved or deteriorated over time, nor does it appear relevant to the Operating Performance Objective to determine the efficiency and effectiveness of the government's management of its assets and liabilities. In this regard, the cost of the information appears to outweigh the benefit.]

Comment Letter # 5, Office of the Secretary, Department of the Interior

See section above titled “DOI Response to Current Draft ED Requirements” for DOI’s response to the question.

Comment Letter # 7, Government Accountability Office

[W]e have concerns about the costs versus the benefits of accumulating, [p]reparing, and auditing information required by paragraph 34 to be reported in disclosures for fiduciary activities. Requiring the Federal entities to disclose the value of oil and gas reserves for fiduciary activities will incur additional costs and result in information that is inconsistent with information currently reported to beneficiaries of these fiduciary activities. In addition, it will reflect only the value of reserves for which the entity has fiduciary responsibility, which may not represent all reserves owned by beneficiaries.

The Board should obtain specific information from the management of affected entities concerning the costs of developing and reporting the RSI and fiduciary information, and should reconsider the requirements of the ED based on this information. Further, the Board should clearly document the basis for its determination of whether such information is appropriate for general purpose financial statements and whether it can be prepared and audited at a reasonable cost in relation to its usefulness.

Comment Letter # 8, Greater Washington Society of CPAs

The Uniform Principal and Income Act, enacted by at least 43 states limits responsibility of a fiduciary to cash received, invested and disbursed, and prudent holding of non-cash assets. While SFFAS 31 will require disclosure of land assets held in the two Indian Trust Funds, it will be extraordinarily difficult to record proved oil and gas resources in the financial statements of the two Indian Trust Funds, and certainly a challenge for a November 15 completion of the audits thereof. The number of oil and gas leases on Indian lands (approximately 55 million acres – 45 million tribally-owned and 11 million owned by individual Indians) is disproportionately large since the individual holdings are small compared to other Federal Government leases on its own holdings.

FISC concurs that extension of reporting of oil and gas leases and valuing the proved reserves related thereto would cost far more than any useful information provided therewith. Interior now reports undivided and divided land interests owned by tribes and individual Indians and leases thereon (exploratory, producing and non-producing) in quarterly statements to the tribal and individual account holders. This can be seen in the following data taken from the Mineral Management Service web site. (This information has either been taken directly from the web site or has been derived from information taken from the website.)

MMS Summary of Oil and Gas Lease Data Producing and Non-Producing Leases – Fiscal Year 2007

	American Indian Leases	Total Federal Government Leases
Number of Leases	4,119*	63,610
Percentage of Total Leases	6.1%	93.9%
Leased Acreage	2,069,459**	91,595,981**
Percentage of Leased Acreage	2.2%	97.8%
Average Acreage Per Lease	502	1,440
Total Oil & Gas Royalties	\$317,735,000	\$9,256,032,000
Percentage of O & G Royalties	3.3%	96.7%

*Many of these leases cover lands jointly owned by one or more tribes and many undivided individual Indian interests.

**67,792,121 (74.0%) Federal Government acres are non-producing vs. 152,971 (7.4%) non-producing Indian acres.

Question 1: As stated in DOI’s comment letter on the May 2007 ED, why does DOI believe the disclosure would need to be disaggregated? How would it be disaggregated? The methodology that is used to develop the number may require more detailed research, but the proposed standard does not require the information that is disclosed in the note to be disaggregated.

Question 2: SFFAS 31, par. 12, states that “Fiduciary assets may include assets other than cash, e.g., real or personal property held temporarily pending disposition, or held long-term in a fiduciary capacity.” There does not seem to be disagreement over whether natural resources on trust lands meet the definition of fiduciary assets. The issue is whether the cost of disclosing fiduciary assets measured in conformance with this proposed standard exceed the benefits to be achieved. In order for the board to consider the perceived benefits against the costs, please provide an estimate of what it would cost to disclose the value of estimated fiduciary petroleum royalty assets, liabilities, and related inflows and outflows.

Staff Recommendation

SFFAS 31, par. 12, states that “Fiduciary assets may include assets other than cash, e.g., real or personal property held temporarily pending disposition, or held long-term in a fiduciary capacity.” There does not seem to be disagreement over whether natural resources on trust lands meet the definition of fiduciary assets. The issue is whether the cost of disclosing fiduciary assets and liabilities measured in conformance with this proposed standard exceed the benefits to be achieved.

This file was sent to the DOI representative on January 8, 2009, and January 15, 2009. The DOI representative replied that they would not be able to talk to staff regarding the issue until mid-February at the earliest. Therefore, staff recommends that the board retain the disclosure requirements for fiduciary oil and gas resources from par. 48 of the December 2008 draft ED until FASAB receives further cost information from DOI in order to make an informed decision.

Evolution of the Disclosure Requirements for Fiduciary Oil and Gas Resources

The Natural Resources Task Force Discussion Paper, *Accounting for the Natural Resources of the Federal Government*, issued in June 2000, stated that “One member of the task force from Interior also believes that there must be more detailed reporting to tribes and individual Indians regarding trust lands and resources, including information on earned revenue and, if estimable, quantity and value of natural resources available for sale.”

The December 2002 FASAB board meeting minutes for the natural resources session includes the following brief discussion of fiduciary assets: “Mr. Jacobson [FASAB General Counsel] asked how this project would relate to mineral rights on Indian lands. Chairman Mosso explained that Indian assets would be reported on some sort of fiduciary balance sheet and the FASAB standards would be followed to account for them.”

The October 2003 staff memo contained the following note: “This proposed standard is silent with respect to disclosures related to fiduciary oil and gas activities (e.g., American Indian). Staff is working to ensure that the fiduciary activities standards – currently under review – result in the same disclosures for fiduciary oil and gas activities as proposed here for federally owned oil and gas activities. Staff believes that disclosures for fiduciary oil and gas activities are best presented as an integral part of the fiduciary activities disclosures.”

A December 2005 version of the ED contained the following proposed requirement:

Fiduciary Oil and Gas Resources Disclosures

47. Fiduciary oil and gas activities should be presented as an integral part of the fiduciary activities disclosures.

The final ballot draft of SFFAS 31, *Accounting for Fiduciary Activities*, was approved at the March 30, 2006 board meeting. Reporting on fiduciary natural resources was not explicitly mentioned in that standard.

A May 2006 version of the ED contained the following revised proposed requirement:

Disclosure Requirements for Fiduciary Oil and Gas Resources

29. Fiduciary activities are defined in SFFAS 31. Fiduciary oil and gas activities information consistent with the foregoing requirements should be presented as an integral part of the fiduciary activities disclosures.

A July 2006 version of the ED contained the following revised proposed requirement and a related question for respondents:

Disclosure Requirements for Fiduciary Oil and Gas Resources

28. Fiduciary activities are defined in SFFAS 31, *Accounting for Fiduciary Activities*. Fiduciary oil and gas information consistent with the foregoing requirements for asset valuation should be presented about estimated petroleum royalties managed through fiduciary activities as an integral part of the fiduciary activities disclosures.

Question for Respondents

5. SFFAS 7 (amended by SFFAS 27 for earmarked funds) requires that agencies report on assets held in a fiduciary capacity (see par. 83 to 87). The Board recently approved but has not yet released SFFAS 31, *Accounting for Fiduciary Activities*. SFFAS 31 will supersede SFFAS 7 with respect to fiduciary activities but continues the requirement to report on assets held in a fiduciary capacity. The Department of Interior (the department) manages oil and gas resources on behalf of individual Indians and Indian tribes. Currently, the department does not include any information regarding fiduciary oil and gas resources in its disclosures. This proposed standard – because it classifies oil and gas resources as assets – would result in additional information being disclosed for oil and gas assets managed in a fiduciary capacity. Note, however, that fiduciary reporting does not extend to inclusion of the additional disclosures or required supplementary information that are proposed for Federal oil and gas resources. Thus, only disclosures of the assets would result from this proposal.

Some members have expressed concern that the costs may exceed the benefits of disclosing fiduciary assets and liabilities measured in conformance with generally accepted accounting principles. Since this proposal may significantly increase the fiduciary assets qualifying for disclosure by the department, we are requesting input on the cost-benefit of the requirement with respect to fiduciary activities. (See paragraph 28)

A November 2006 version of the ED contained the following revised proposed requirement and question for respondents:

Disclosure Requirements for Fiduciary Oil and Gas Resources

33. Fiduciary activities are defined in SFFAS 31, *Accounting for Fiduciary Activities*. Information consistent with the foregoing requirements ~~for asset valuation should be presented about estimated petroleum royalties managed through fiduciary activities as an integral part of the fiduciary activities disclosures Schedules of Fiduciary Activity and Net Assets.~~ No additional disclosures or RSI are required.

Question for Respondents

5. Statement of Federal Financial Accounting Standards (SFFAS) 7 ~~(as amended by SFFAS 27 for earmarked funds)~~ requires that agencies report on assets held in a fiduciary capacity (see par. 83 to 87). The Board recently ~~approved but has not yet released~~ issued SFFAS 31, *Accounting for Fiduciary Activities*. SFFAS 31 will supersede SFFAS 7 with respect to fiduciary activities but continues the requirement to report on assets held in a fiduciary capacity. The Department of Interior ~~(the department)~~ manages oil and gas resources on behalf of individual Indians and Indian tribes. ~~Currently, the department does not include any information regarding fiduciary oil and gas resources in its disclosures.~~ This proposed standard – because it classifies oil and gas resources as assets – would result in additional information being disclosed for oil and gas assets managed in a fiduciary capacity. Note, however, that fiduciary reporting does not extend to inclusion of the additional disclosures or ~~RSI~~ required supplementary information that are proposed for Federal oil and gas resources. Thus, only disclosures of the assets would result from this proposal.

Some members have expressed concern that the costs may exceed the benefits of disclosing fiduciary assets and liabilities measured in conformance with generally accepted accounting principles. Since this proposal may significantly increase the fiduciary assets qualifying for disclosure by the department, we are requesting input on the cost-benefit of the requirement with respect to fiduciary activities. (See paragraph 2833)

- a. Do you believe it is cost-beneficial to require disclosure of the value of fiduciary oil and gas resources? Please explain the basis for your beliefs.

The final May 2007 ED contained the following revised proposed requirement and question for respondents:

Disclosure Requirements for Fiduciary Oil and Gas Resources

34. Fiduciary activities are defined in SFFAS 31, *Accounting for Fiduciary Activities*. Information consistent with the ~~foregoing~~ requirements of paragraphs 16 through 29 and 37 through 45 of this document ~~should~~ shall be presented as an integral part of the fiduciary activities Schedules of Fiduciary Activity and Net Assets. No additional disclosures or RSI are required.

Question for Respondents

5. Statement of Federal Financial Accounting Standards (SFFAS) 7, *Accounting for Revenue and Other Financing Sources* (as amended), requires that agencies report on assets held in a fiduciary capacity ([footnoted]SFFAS 7, paragraphs ~~see par-~~ 83 to 87). The Board recently issued SFFAS 31, *Accounting for Fiduciary Activities*. SFFAS 31 will supersede SFFAS 7 with respect to fiduciary activities but continues the requirement to report on assets held in a fiduciary capacity. The Department of Interior (DOI) manages oil and gas resources on behalf of individual Indians and Indian tribes. This proposed standard – because it classifies oil and gas resources as assets – would result in additional information being disclosed for oil and gas assets managed in a fiduciary capacity. Note, however, that fiduciary reporting does not extend to inclusion of the additional disclosures or RSI that are proposed in this document for Federal oil and gas resources. Thus, with respect to fiduciary activities, only disclosures of the assets, liabilities, and related inflows and outflows would result from this proposal.

Some Board members have expressed concern that the costs may exceed the benefits of disclosing fiduciary assets and liabilities measured in conformance with ~~generally accepted accounting principles~~ this proposed standard. Since this proposal may significantly increase the fiduciary assets ~~qualifying for disclosure by the department~~ disclosed, we are requesting input on the cost-benefit of the requirement with respect to fiduciary activities. (See paragraph ~~334~~).

- a. Do you believe it is cost-beneficial to require disclosure of the value of fiduciary oil and gas resources, estimated fiduciary petroleum royalty assets, liabilities, and related inflows and outflows? Please explain the basis for your beliefs.

Issue Paper No. 3: Liability Classification

Current Draft ED Requirements

The current draft exposure draft (ED) does not address the classification of the liability for revenue distributions to others (i.e., current or non-current).

DOI Response to Current Draft ED Requirements

In response to question 8 on the present value (PV) field test questionnaire, the field test team stated that:

“Long term vs. short term liabilities: The Exposure Draft and accompanying Appendix C do not break out or distinguish between long or short term liabilities, nor does the pro forma balance sheet present them separately, in relation to the nature of the offsetting assets. While it is understood that the Appendix C entries and statements are illustrative and not meant to present all associated detail, the break out and disclosure of long term vs. short term liabilities is a financial reporting requirement, and poses some issues around implementation. In order to comply with reporting requirements of OMB Circular A-136 and FASAB SFFAS 1, current liabilities must be reported separately from non-current (long term) liabilities.

Clearly, the royalty reports and cash received that remain unmatched at the end of a reporting period are current, as they are generally remitted on the legal due date, and payable in the subsequent month. We request that this be clarified in the Statement and Appendices. However for the new asset ‘Estimated Petroleum Royalties’, no mention is made that any portion of the associated liability might be short term or ‘current’.

FASAB SFFAS 1, pp 83 states that, “Other current liabilities may include unpaid expenses that are accrued for the fiscal year for which the financial statements are prepared and are expected to be paid within the fiscal year following the reporting date.” Further, pp. 86 requires, “The reporting entity should disclose the amount of current liabilities not covered by budgetary resources.” And the Glossary defines current liabilities as, “Amounts owed by a federal entity for which the financial statements are prepared, and which need to be paid within the fiscal year following the reporting date.”

For the liability related to ‘Estimated Petroleum Royalties’, some amount will be liquidated and transferred to recipients in the subsequent year, and should therefore be reported as current. The entries demonstrated in Appendix C for the recipient ‘Other Federal Component Entity’ would likewise be affected. We request this be discussed in the Standard and associated Appendices.

The methodology for computing what this current portion might be is subject to debate, but must at least be fairly readily computed, in order to meet short timelines for annual financial statement preparation. It could be based upon the same value reported as depletion expense in the current year. This would be perhaps the best method, as the value would already be computed, reconciled, and audited, and would be most representative of current market conditions that could be expected to occur in the immediately subsequent year.

However, its complexity is greatly increased if it must only relate to oil and gas, as the current ED only includes oil & gas.

If, FASAB determines that the liability related to ‘Estimated Petroleum Royalties’ should be all classified as long-term (non-current), we request that the Statement clarify this point for implementation.

Federal Financial Reporting Requirements

SFFAS 1, Accounting for Selected Assets and Liabilities

Other Current Liabilities

83. The term other current liabilities is used to report current liabilities that are not recognized in specific categories such as accounts payable; interest payable; debt owed to the public, Treasury, or other entities; and liabilities for loan guarantee losses. Other current liabilities may include unpaid expenses that are accrued for the fiscal year for which the financial statements are prepared and are expected to be paid within the fiscal year following the reporting date.
84. Typical examples of other current liabilities to be recognized are: (a) accrued employees’ wages, bonuses, and salaries for services rendered in the current fiscal year for which paychecks will be issued in the following year; (b) accrued entitlement benefits payable, such as Old Age Survivors Insurance (OASI) and Veterans Compensation and Pension benefits applicable to the current period but not yet paid, and (c) annuities for the current fiscal year administered by trust, pension, or insurance programs for which payment would be made in the following fiscal year. Such liabilities may be presented on the face of the financial reports as Other Current Liabilities or as one or more separate categories depending on the materiality of the amounts.
85. Federal entities may receive advances and prepayments from other entities for goods to be delivered or services to be performed. Before revenues are earned, the current portion of the advances and prepayments should be recorded as other current liabilities. After the revenue is earned (goods or services are delivered, or performance progress is made according to engineering evaluations), the entity should record the appropriate amount as a revenue or financing source and should reduce the liability accordingly. Other current liabilities due to federal entities are intragovernmental liabilities that should be reported separately from those due to employees and the public.
86. The reporting entity should disclose the amount of current liabilities not covered by budgetary resources. The U.S. government-wide financial statements need not include this disclosure.

OMB Circular A-136, Financial Reporting Requirements

II.4.10.17 Note 17 Other Liabilities

	<u>Non-Current</u>	<u>Current</u>	FY2xxx (CY) <u>Total</u>
A. 1. Intragovernmental			
(1) _____	\$ xxx	\$ xxx	\$ xxx
(2) _____	xxx	xxx	xxx
(3) _____	<u>xxx</u>	<u>xxx</u>	<u>xxx</u>
Total Intragovernmental	xxx	xxx	xxx
2. _____	xxx	xxx	xxx
3. _____	xxx	xxx	xxx
4. _____	<u>xxx</u>	<u>xxx</u>	<u>xxx</u>
Total Other Liabilities	\$ <u>x,xxx</u>	\$ <u>x,xxx</u>	\$ <u>x,xxx</u>

	<u>Non-Current</u>	<u>Current</u>	FY2xxx (PY) <u>Total</u>
B. 1. Intragovernmental			
(1) _____	\$ xxx	\$ xxx	\$ xxx
(2) _____	xxx	xxx	xxx
(3) _____	<u>xxx</u>	<u>xxx</u>	<u>xxx</u>
Total Intragovernmental	xxx	xxx	xxx
2. _____	xxx	xxx	xxx
3. _____	xxx	xxx	xxx
4. _____	<u>xxx</u>	<u>xxx</u>	<u>xxx</u>
Total Other Liabilities	\$ <u>x,xxx</u>	\$ <u>x,xxx</u>	\$ <u>x,xxx</u>

C. Other Information: _____

Instructions

Other Liabilities. Include all liabilities not reported elsewhere. Separately disclose the current portion of other liabilities.

Other Information. Provide other information necessary for understanding other liabilities.

Source: OMB Circular A-136, Financial Reporting Requirements, available online at http://www.whitehouse.gov/omb/assets/omb/circulars/a136/a136_revised_2008.pdf.

DOI Financial Statement Preparation Guidance¹

Chapter 2 – Balance Sheet

3. Current and Non-Current Liabilities

Current Liabilities: Probable future outflow or other sacrifice of resources as a result of past transactions or events whose liquidation is reasonably expected to occur within a relatively short period of time, usually 12 months.

Non-Current Liabilities: Probable future outflow or other sacrifice of resources as a result of past transactions or events whose liquidation is reasonably expected to occur beyond one year.

- SGL Account 2225.G *Unfunded FECA Liability* as a Department is expected to be 40% Current and 60% Non-Current, based on analysis.
- Each bureau is expected to analyze other SGL Accounts and determine the current and non-current portions. As a rule, it is not reasonable to disclose that certain SGL Accounts are always current or non-current.

Chapter 5 – Notes to the Financial Statements

11. Liabilities Analysis

OMB Circular A-136 requires Federal agencies to separately disclose, in a footnote, information concerning intragovernmental liabilities not covered by budgetary resources separately from other liabilities not covered by budgetary resources. Liabilities not covered by budgetary resources are liabilities for which Congressional action is needed before budgetary resources can be provided. OMB Circular A-136 also requires a separately disclosed footnote for other liabilities not disclosed elsewhere and divided into the current and non-current portions. **The Liabilities Analysis footnote provides an analysis of the liabilities on the Balance Sheet by incorporating both A-136 requirements into one footnote.** [emphasis added]

Bureaus are required to prepare this footnote using the Hyperion FOOT_05 application and the Department's standard format for operating leases file located on the X Drive of the Citrix Server.

Bureaus should provide other information as necessary in the text of the footnote to provide the reader an understanding of their liabilities.

See "Note 15. Liabilities Analysis" excerpted from DOI's Fiscal Year 2008 Performance and Accountability Report on page 5 for DOI's breakdown of all liabilities by current and non-current.

¹ Available online at www.doi.gov/pfm/fs_guidance; last accessed February 10, 2009.

Excerpt from DOI Fiscal Year 2008 Performance and Accountability Report

Notes to Principal Financial Statements

NOTE 15. LIABILITIES ANALYSIS

Liabilities covered by budgetary resources are funded liabilities to be paid with existing budgetary resources. Liabilities not covered by budgetary

resources represent those unfunded liabilities for which congressional action is needed before budgetary resources can be provided.

Interior's liabilities covered and not covered by budgetary resources as of September 30, 2008, are as follows:

(dollars in thousands)	Covered by Budgetary Resources		Not Covered by Budgetary Resources		FY 2008
	Current	Non-Current	Current	Non-Current	
Intragovernmental Liabilities:					
Accounts Payable	\$ 50,224	\$ -	\$ -	\$ 581,401	\$ 611,625
Debt	50,000	665,109	-	-	715,109
Other					
Liability for Capital Transfers to the General Fund of the Treasury	-	-	44,807	2,005,859	2,050,466
Advances and Deferred Revenue	542,126	-	109	388	542,603
Custodial Liability	-	-	538,933	143,016	681,949
Other Liabilities					
Accrued Employee Benefits	51,041	-	28,025	39,480	118,546
Judgment Fund	-	-	-	192,580	192,580
Unfunded FECA Liability	-	-	29,703	58,709	88,412
Other Miscellaneous Liabilities	120	-	154,563	6,982	161,665
Total Other Liabilities	51,181	-	212,291	295,751	559,203
Total Other Intragovernmental Liabilities	593,287	-	795,940	2,444,994	3,834,221
Total Intragovernmental Liabilities	693,511	665,109	795,940	3,006,395	5,160,955
Public Liabilities:					
Accounts Payable	889,467	70,741	-	-	960,208
Loan Guarantee Liability	-	36,180	-	-	36,180
Federal Employee and Veterans' Benefits					
U.S. Park Police Pension Actuarial Liability	-	-	-	665,782	665,782
U.S. Park Police Pension Current Liability	36,318	-	-	-	36,318
FECA Actuarial Liability	-	-	-	681,123	681,123
Total Federal Employee Veterans' Benefits	36,318	-	-	1,346,905	1,383,223
Environmental and Disposal Liabilities	-	-	510	155,038	155,548
Other					
Contingent Liabilities	-	-	-	1,188,548	1,188,548
Advances and Deferred Revenue	375,188	-	392,983	292,455	1,060,626
Payments Due to States	-	-	494,877	137,407	632,284
Grants Payable	292,228	-	-	-	292,228
Other Liabilities					
Accrued Payroll and Benefits	235,277	-	-	-	235,277
Unfunded Annual Leave	-	-	50,953	328,777	379,730
Capital Leases	5,385	924	-	21,748	28,057
Custodial Liability	-	-	25,126	-	25,126
Secure Rural Schools Act Payable	-	-	92,083	-	92,083
Storm Damage	42,389	78,685	-	-	121,054
Other Miscellaneous Liabilities	968	2,307	19,468	53,775	76,518
Total Other Liabilities	283,999	81,916	187,630	404,300	957,845
Total Other Public Liabilities	951,415	81,916	1,075,490	2,022,710	4,131,531
Total Public Liabilities	1,877,200	188,837	1,076,000	3,524,653	6,666,690
Total Liabilities	\$ 2,570,711	\$ 853,946	\$ 1,871,940	\$ 6,531,048	\$ 11,827,645

Staff Analysis and Recommendation

DOI presents a voluntary breakout of current and non-current liabilities for all liabilities. This disclosure is neither required nor discouraged by FASAB standards or OMB Circular A-136.

DOI has asked for clarification on the classification (current vs. non-current) of the liability related to estimated petroleum royalties to be distributed. Staff proposes that the following changes be incorporated into the ED:

- 30-28. A long-term liability for revenue distributions to ~~others~~ non-federal entities (e.g., state governments) should be recognized on the balance sheet of the component entity that is responsible for collecting royalties in conjunction with the recognition of an asset for estimated petroleum royalties. The amount of the liability ~~shall~~ should be estimated based on the present value of the royalty share of the federal proved oil and gas reserves designated to be distributed to ~~others, e.g., the states, the general fund of the U.S. Treasury and other federal agencies~~ non-federal entities. For example, the average annual share of the revenue distributed to ~~others~~ non-federal entities over the preceding twelve (12) months may be an acceptable basis for estimating petroleum royalties to be distributed to ~~others~~. Other methodologies may be acceptable.
29. The estimated portion of the liability for revenue distributions to non-federal entities expected to be distributed within 12 months of the fiscal year-end may be classified as current.

Issue Paper No. 4: Depletion Expense

December 2008 Draft ED Requirements

The December 2008 draft of the revised exposure draft (ED) on *Accounting for Federal Oil and Gas Resources* contains the following proposed requirements related to recognition of depletion expense that were carried forward from the May 2007 ED, revised only to exclude reference to the separate components of oil and gas (oil and lease condensate, NGPL, and gas) and update the paragraph number.

33. Royalties from the production of federal oil and gas proved reserves shall be recognized as exchange revenue on the statement of net cost by the component entity that is responsible for collecting the royalty revenue. At the same time, an amount equal to the royalty revenue shall be recognized as depletion expense on the statement of net cost of the component entity that is responsible for collecting the royalty revenue; and, the value of estimated petroleum royalties shall be reduced by the depletion expense amount. [footnote omitted]

DOI Response to Current Draft ED Requirements

In its comment letter, DOI stated that:

“As a result of timing issues related to royalty reporting, and the use of estimates and accruals in revenue figures, the field test questionnaire provides a detailed discussion of factors requiring clarification in the Statement. The recommended method would be to record depletion based upon royalty reporting lines received and accepted for the preceding twelve sales months for which royalty production data is available at fiscal year end. This would preclude the need to include estimates in the depletion calculations, which may not relate to oil or gas, and would represent a realistic value of true asset depletion based on actual royalty reporting. This method would likely yield a more accurate picture of current asset depletion over a year time period. This method would also provide the ability, with sophisticated queries and reports, to derive the detailed information the ED requires from actual royalty reports, such as commodity type, region, onshore vs. offshore and other necessary details.”

In response to question 6 on the present value (PV) field test questionnaire, the field test team stated that:

“There are extensive issues discussed below around the many components of revenue recognized by the collecting entity, the relationship of that revenue to depletion expense, and the present or future ability to obtain information at the level of detail presented in the ED. This is a significant set of issues that we believe must be addressed before the ED is finalized.

The ED proposes to base depletion expense upon oil & gas ‘royalty revenue earned’ for the fiscal year ([par.] 23, and Appendix C, entry #6), and is silent regarding what components would comprise this value, except that [par.] 23 refers to ‘royalties from the production’ of proved reserves. This introduces many complexities, including whether or how to include estimates such as the ‘royalty accrual’ (discussed below), and **the**

relationship between revenue recorded in the current fiscal year for royalty reporting adjustments made to prior years and current year depletion expense.

Revenue earned by the collecting entity generally consists of amounts reported or billed, cash for which no royalty report has been received (unmatched cash), and amounts accrued as estimates. There is not a simple means at this time to obtain detail which reconciles to the general ledger and financial statements, of all components of earned revenue specifically related to oil and gas and more specifically related to offshore vs. onshore leases.

Earned Revenue Based Upon Royalty Reports; Royalty Adjustments to Prior Periods:

In addition to current royalty amounts, MMS records earned revenue in the current period for the sum of both positive and negative amounts resulting from upward or downward adjustments to prior royalty reporting, related to previous months when the commodity had been either sold or removed from the lease (**sales months**). This is a standard business process in oil and gas industry reporting, resulting from the receipt of subsequent information related to previous reporting periods that was unknown when the compulsory reporting was legally due, such as revised pipeline statements. These adjustments frequently cross monthly, quarterly, and fiscal year boundaries, can be large amounts, and are routine.

If depletion expense is linked across the board with overall revenue earned in the current year, then it must be understood that it would be at least partially based on revenue earned in the current year that is related to adjustments to prior periods falling outside the fiscal year. Therefore, the asset would be depleted in the current year based upon activity that does not actually reflect true depletion in the actual year.

If depletion expense were alternatively based upon revenue earned for oil & gas royalty reports related to current year production only, to most closely reflect the actual asset depletion in the current year, it would be applicable to only the **sales months** falling within the fiscal year. This would exclude prior period adjustments to royalty reporting that would be deemed unrelated to depletion in the current year.

However, complete royalty reporting covering production in the current fiscal year measured at 9/30 can only be ascertained through August, which covers actual reported royalty production through June (for which delayed reporting would not be due until August if a paid estimate were in place). In other words, only 9 months of complete sales month (production) data within a given fiscal year are available at 9/30 if basing 'revenue earned' and depletion expense only on current fiscal year sales months; October through June. Clearly, this would not present a complete picture of current year asset depletion, because it would not even include a full 12 months of royalty reporting.

Recommended Depletion Method:

The recommended alternative is to record depletion based upon royalty reporting lines received and accepted for the preceding 12 sales months available at fiscal year end; July through June (received through August, fully available in September). This would preclude the need to include estimates in the depletion calculations (discussed below), and would represent a realistic value of true asset depletion based on actual royalty reporting. **Revenue earned would not be a perfect match in the fiscal year, but in this case it should not, because depletion in the current year should not be linked to prior adjustments not related to the current year.** To do otherwise would *include* prior period adjustments not related to depletion in the year, and would involve complex and extensive inclusion of current year estimates that also include prior period adjustments. **This method would likely yield a more**

accurate picture of current asset depletion over a year span. This method would also provide the ability, with sophisticated queries and system reports, to derive the detailed information the ED requires from actual royalty reports, such as commodity type, Region, onshore vs. offshore and other necessary details.

Another alternative would be to record depletion based solely upon all royalty lines received and accepted during the fiscal year, excluding all accruals and regardless of sales month. Again, revenue earned would not be a perfect match in the fiscal year, because accruals would be excluded. But including all lines accepted in a year would eliminate the need to include complex and extensive current year-end estimates for which disclosure detail is not available (see discussion below) because actuals over a 12 month span would be fully included. This method would, however, include all adjustments to prior reporting received in the current fiscal year, and while it may provide a closer tie to actual revenue reported in the financial statements, it would not be as fair a measure of asset depletion in the year. This method, like the recommended method above, would provide the ability, with sophisticated queries and system reports, to derive the detailed information the ED requires from actual royalty reports, such as commodity type, Region, and other necessary details.

Earned Revenue; Document Level Royalty Reporting Accruals vs. Line Level Royalty Detail:

When a royalty document is received, it usually includes numerous individual 'lines' of reporting. Each line contains specific detail about the royalty, such as the individual lease number, sales month and product code. If even one line of the royalty document passes edits and accepts in the royalty accounting system (MRMSS), then revenue is recorded for the full 'document calculated total'. If all lines reject, then a manual accrual is made for the full 'document calculated total'. Priority is placed on clearing rejected lines as quickly as possible, generally in the month following receipt. In subsequent periods, as the previously rejected royalty lines are corrected and accept in the MRMSS, they do not give rise to revenue, as it was already properly accrued when the document was first received.

As you can see, the detail required in the ED for 'earned revenue' by oil or gas and onshore vs. offshore is not readily obtainable for this portion of the population (rejected lines in the last month of the year). For purposes of the field study, CRB undertook an initial effort to ascertain in a 1-month period, the detail related to line level royalty revenue earned by oil or gas and onshore vs. offshore. In instances where the doc calc total giving rise to revenue in the period did not equal the sum of the accepted lines in the system, CRB developed a method to allocate (estimate) earned revenue to detail associated with existing lines. **This identified a significant problem in our ability to report accurately on the detail associated with 'earned revenue' based on current month royalty reporting. In many cases, the revenue was allocated to oil or gas based upon an estimate that may or may not be correct, and which may not prove to be correct in subsequent periods when the rejected lines are corrected and accept in the system. This issue further supports the premise that depletion be based solely upon accepted royalty reporting lines for given sales months, as presented above, and not on accruals and estimates.**

Earned Revenue; Estimates and Manual Accruals: When examining 'earned revenue' and its relationship to asset depletion, CRB performed an extensive analysis for the field study, of estimates and manual accruals related to current period royalty revenue.

MMS records numerous manual accruals to fairly present assets, liabilities and revenue in the financial statements. One such entry is the 'royalty accrual', a large accrual that represents estimated production in the current month for oil, gas and solid minerals, where the royalty reports are not yet received. The royalty accrual is not computed based

on sales month (production month), but rather upon when the royalty report was received. It is computed based on a 12-month average of previous royalty reports received. Revenue recognition for royalty is consistent therefore, because **prior period adjustments to previous royalty reporting are treated as current year revenue, upward or downward, and factored into the current period royalty accrual. The royalty accrual is subject to extensive year-end audit review, and a large subsequent adjustment may be required annually, later in the financial reporting process (early November). If included in the revenue matched with depletion expense, this would also then, require that the proved reserves asset be adjusted accordingly, and would impact materially, all allocated downstream recipients as well.**

The royalty accrual is required to be performed fairly quickly, at the high level, to meet accelerated financial reporting objectives. **It includes adjustments to prior reporting periods, and it does not contain the detail required in the ED, to break out oil vs. gas and onshore vs. offshore.** Of course, a rough estimation method could always be developed, but its accuracy and validity when compared to subsequent actual information could potentially prove to be incorrect.

Another significant manual accrual involves **unmatched cash** for which no royalty report has been received at the end of the reporting period. This occurs monthly, and this large unmatched cash balance can not accurately be linked to oil or gas, onshore or offshore. In some instances, large compliance settlement amounts may be included in the cash balance, not related to current year royalties. Large amounts could be related to interest payments. It would be incorrect to allocate current year depletion to unmatched amounts that may not be related. **Also, this unmatched cash, when applied to subsequent royalty reports, will likely relate to adjustments to prior reporting, and also not bear a relationship to current year asset depletion.**

Previous discussions with FASAB Staff indicated that in order to provide matching of royalty revenue earned in the fiscal year, the royalty accrual would be included in the 'revenue earned' that would be offset by depletion expense, because the accrual estimates production in the current month for which royalty reports will not be yet be received. Also, it was discussed that revenue recognition overall should remain consistent, and that revenue earned in the fiscal year, regardless of sales (production) month and subsequent adjustments, would still apply. Accordingly, the text in pp. #23 and throughout the Statement was going to be revised to include, "Royalties received and accrued..."

However, upon analysis **as a result of the field test study**, it is apparent that the degree of detail required to be estimated, allocated and reported is very extensive, labor intensive, **includes adjustments to prior period reporting which may not relate to current period asset depletion at all, and poses significant risks to meeting audit and accelerated financial reporting objectives.** Again, including these and other estimates, by default, **includes adjustments to prior reporting, or other activity not necessarily related to actual current period asset depletion. The degree of detail for disclosure required in the ED would not be readily available from these estimates, and would have to be extensively estimated.** And the inclusion of these estimates would likely not yield a better, and perhaps a worse, measure of actual asset depletion in the year, as opposed to the recommended sales month method described above. For the many complex accruals currently performed by MMS, estimation methods would have to be developed to allocate some portion of the earned revenue to oil and gas, and then of that subset, to onshore vs. offshore.

For purposes of this field test study, revenue overall is presented in aggregate, includes estimates and is based upon royalty reporting lines received and

accepted in the fiscal year, regardless of sales months, to tie with current practices. This is done to illustrate the many estimates performed, their relationship to earned revenue, and to explain why the detail required in the ED can not currently be provided. However, it is not the recommended method for deriving depletion expense. Also, disclosures were not attempted.

As we have discussed, estimations pose significant challenges to MMS' ability to produce adequate detail in the required disclosures regarding revenue earned by oil and gas and onshore vs. offshore categories. **It currently could not be readily done with existing resources or information.** Each line of each component of earned revenue would have to be carefully analyzed, an allocation method developed for oil and gas and onshore vs. offshore, and would be an extensive and labor intensive process. A sophisticated system report and queries could be developed to help provide some of this degree of detail, but it would not resolve issues around allocations of estimates, and **timing would be crucial, as reconciliations and adjusting entries would need to be made quickly, to meet accelerated financial reporting deadlines, and to pass audit requirements.**

The matrix below presents some of the key components of 'earned royalty revenue' presently recorded by MMS, and demonstrates how the earned royalty revenue value was estimated for the illustrative pro forma entries. It must be noted that in actual practice, the previous year-end estimate would be reversed in the subsequent year, so that actual revenue recorded in any given year related to estimates would essentially reflect the **change** associated with those estimates over the year. In this example, for the study, the full values were presented, to give the reader a general idea of the relative sizes of the estimates under discussion.

Again, the primary concerns related to recording depletion expense based on revenue which includes estimates revolve around mismatching unrelated portions of estimates with actual asset depletion, potential material audit findings and a potential inability to meet accelerated financial reporting objectives.

As an aside, if using the recommended sales month method described above for ascertaining the amount of depletion to record in a fiscal year, then the actual royalty value for oil and gas reported to MMS was approximately \$9.2 billion for the most recent sales months available when performing the field test, June 2006 through May 2007, obtained in mid-August 2007.

To restate, some of the key concerns around recording depletion expense based upon the sum of current year royalty reports and estimates include:

- Revenue and depletion expense would be mismatched due to prior period adjustments not related to current period depletion captured as revenue in the current year.
- The revenue estimate including accruals would also include estimates of production anticipated through year-end, and estimates of unmatched cash with estimates sub-allocated to oil & gas, and then sub-allocated to onshore vs. offshore. The estimated allocations will likely be later found to be incorrect. Also, the estimates include adjustments to prior periods, not attributable to depletion in the current period.
- Each estimate is already complex to derive, and currently does not include a method for allocating to oil or gas, or onshore vs. offshore.
- Revising each estimate accordingly will decrease the likelihood of meeting accelerated financial reporting objectives, and will increase the likelihood of audit failures, and their severity based on materiality.
- Estimates and subsequent changes to estimates will impact the asset value through depletion expense, and so, all designated downstream recipients.

- Estimates measured against subsequent actuals at fiscal year end will likely result in material adjustments near the close of the annual financial audit process in early November, and also require adjustment by designated downstream recipients.”

Analysis of Components - Oil & Gas Revenue Earned - Entry #6, FASAB ED

Amounts are representational and illustrative only, to present basic concepts, and are not necessarily based on final or actual numbers

Total Royalty Report Line Level Data Received in Period (Royalty Value Less Allowances - RVL A)	10,731,532,649
Royalty line amounts that do not give rise to revenue by collecting entity in period	
Document calculated total equals zero (non-value related adjustments)	246,825,251
No system receivable created, such as for Indian direct pay or Strategic Petroleum Reserve (SPR)	789,559,441
Royalty documents accepted in prior periods where previously rejected lines now accept	<u>17,170,452</u>
Total Royalty Line Amounts That Do Not Give Rise to Revenue by Collecting Entity in Period	1,053,555,144
Revenue From Royalty Lines - Other (Currently Reported in 'Rents and Royalties')	<u>5,333,009</u>
Remainder - Royalty Lines Giving Rise to Revenue Received in Fiscal Year, Attributable to Oil & Gas	9,672,644,496
Accrued Revenue and Estimates - O&G (Illustrative Ending Balances Only - Revenue would be recorded for change in accruals)	
Estimated Portion of Year-End Royalty Accrual Estimating Current Month Production, Oil & Gas	760,179,551
Year-End SPR Accrual Estimating Current Month Production Delivered to DOE, Oil Only	105,216,449
Annual Actual Revenue for Oil Taken In Kind to Fill Strategic Petroleum Reserve (SPR)	200,974,551
Other Invoices In Lieu of Royalty Reports Presumed to be Related to Oil and Gas Royalties	30,000,000
Estimated Royalty Portion of Enforcement Settlements if Related to Current Year - Oil & Gas	50,000,000
Estimated Portion of Numerous Other Revenue Accruals Estimated Allocated to Oil & Gas	200,000,000
Estimated Portion of Unmatched Cash Revenue - No Royalty Report – Allocated to Oil & Gas	500,000,000
Total of Accrued Revenue and Estimates To Be Estimated Allocated to Oil and Gas	1,846,370,551
Total Estimated Royalty Related Revenue and Depletion Expense, Oil & Gas, Fiscal Year 20XX	11,519,015,047
Other Revenue - Non-CY Oil & Gas Royalty	
Revenue from Onshore lease sale bonus and 1st year rents (does not tie to pro forma entries – informational only)	286,344,000
Revenue from Offshore lease sale bonus and 1st year rents (does not tie to pro forma entries – informational only)	387,689,000
Revenue from PY Settlements including Civil Penalties and Interest (Currently reported in 'Rents and Royalties')	80,000,000
Revenue from Royalties - Other Commodities i.e. Solid Minerals (Currently reported in 'Rents and Royalties')	615,752,400
Revenue from Late Payment Interest (Currently reported in 'Rents and Royalties')	60,000,000
Other Commodity Related Miscellaneous Revenue Including Compliance (Currently reported in 'Rents and Royalties')	<u>12,000,000</u>
Total Other Revenue - Non-CY Oil & Gas Royalty	1,441,785,400
Total Revenue Reported on Fiscal Year 20XX Statement of Custodial Activity	12,960,800,447

FASAB Staff Analysis and Recommendation

The December 2008 draft ED requires that an amount equal to the royalty revenue shall be recognized as depletion expense on the Statement of Net Cost of the component entity that is responsible for collecting the royalty revenue and the value of estimated petroleum royalties shall be reduced by the depletion expense amount.

The DOI field test team has proposed that FASAB revise the ED to record depletion based upon royalty reporting lines received and accepted for the preceding 12 sales months available at fiscal year-end: July through June (received through August, fully available in September). The purpose of this revision would be to permit DOI to record the expense while precluding the need to include estimates in the depletion calculations. For example, the year-end revenue accrual is not broken out into the detail required for disclosure by the ED (oil and gas, onshore and offshore) and estimates would need to be developed. Similarly, unmatched cash at year-end is recorded in revenue but does not include the detail required for disclosure by the ED.

DOI is concerned that year-end estimates are already complex to derive and revising each estimate to include a method for allocating to oil or gas and onshore vs. offshore will decrease the likelihood of meeting accelerated financial reporting objectives and increase the likelihood of audit failures, and their severity based on materiality.

The DOI field test team also noted that the use of royalty reporting lines received and accepted for the preceding 12 sales months available at year-end would exclude prior period adjustments that are captured as revenue in the current year but are not related to current period depletion. DOI stated that using their recommended method would likely yield a more accurate picture of current asset depletion over a year's time period.

FASAB staff believes that the depletion approach in the ED was not devised to show the "true" effect on the asset during the period since the quantity gets adjusted again at year-end as part of the revaluation. Rather, the depletion approach was an attempt to ensure that the only bottom line effect on MMS' statement of net cost was the net gain / loss that resulted from quantity and value differences from one year to the next. In other words, the depletion approach in the ED is to "match" depletion expense with revenue recognition.

The June 2004 briefing paper explains that since the true cost of depletion is not known, a dollar for dollar match was deemed to be the best approach.

The revenue and depletion expense for royalty collections would flow through the statement of net cost of operations. The amount of the royalty collection will be recognized as revenue and the same amount will be recognized as the depletion expense. The revenue and expense amounts will be equal because the value of proved reserves depleted on a field-by-field basis currently cannot be calculated. (Source: June 2004 Staff Briefing Paper)

Staff notes that recognizing a depletion expense based on reports of royalty reporting lines received and accepted for the preceding 12 sales months available at fiscal year-end (July through June) would result in a gain or loss on the statement of net cost because revenue would not equal the depletion expense (see attachment A beginning on page 8 for the differences between the October through September accounting year and production year royalty revenue reports for fiscal years 2005 through 2007).

Recommendation: FASAB staff recommends retaining the current requirements related to depletion expense.

Attachment A – Example Royalty Revenue Reports (by Accounting Year and Production Year)

Reported Royalty Revenue by Category
Fiscal Year 2007
(Accounting Year)*

	American Indian	Federal Offshore	Federal Onshore	Total
Coal (ton)	\$ 72,637,117.55	\$	\$ 561,549,251.60	\$ 634,186,369.15
Gas (mcf)	257,646,877.80	2,592,331,832.61	1,794,094,223.26	4,644,072,933.67
NGL (gal)	7,805,196.22	198,221,146.74	162,380,795.36	368,407,138.32
Oil (bbl)	87,529,826.85	3,661,800,666.66	651,924,076.23	4,401,254,569.74
Other Royalties	39,894,814.85	(11,139,467.40)	175,167,338.05	203,922,685.50
Subtotal	\$ 465,513,833.27	\$ 6,441,214,178.61	\$ 3,345,115,684.50	\$ 10,251,843,696.38
Rents	954,721.15	200,993,254.55	65,238,025.18	267,186,000.88
Bonus		373,930,998.00	528,705,219.76	902,636,217.76
Other Revenues	8,093,708.06	3,166,688.80	(4,286,261.84)	6,974,135.02
Subtotal	\$ 9,048,429.21	\$ 578,090,941.35	\$ 589,656,983.10	\$ 1,176,796,353.66
Total	\$ 474,562,262.48	\$ 7,019,305,119.96	\$ 3,934,772,667.60	\$ 11,428,640,050.04

Reported Royalty Revenue by Category
Fiscal Year 2007
(Production Year as of 02/21/2008)*

	American Indian	Federal Offshore	Federal Onshore	Total
Coal (ton)	\$ 72,472,514.58	\$	\$ 572,127,538.07	\$ 644,600,052.65
Gas (mcf)	228,077,084.77	2,536,389,463.08	1,659,283,720.58	4,423,750,268.43
NGL (gal)	11,554,918.42	204,988,632.86	169,595,509.93	386,139,061.21
Oil (bbl)	86,344,998.54	3,575,213,583.61	670,859,161.01	4,332,417,743.16
Other Royalties	10,317,118.97	(18,849,706.71)	63,854,423.62	55,321,835.88
Subtotal	\$ 408,766,635.28	\$ 6,297,741,972.84	\$ 3,135,720,353.21	\$ 9,842,228,961.33
Non Revenue Volumes				
Rents	1,385,654.00	199,642,673.45	64,571,990.92	265,600,318.37
Bonus		372,557,868.00	540,181,989.32	912,739,857.32
Other Revenues	\$ 1,618,465.50	\$ 3,743,036.86	\$ 4,088,365.11	\$ 9,449,867.47
Subtotal	\$ 3,004,119.50	\$ 575,943,578.31	\$ 608,842,345.35	\$ 1,187,790,043.16
Total	411,770,754.78	6,873,685,551.15	3,744,562,698.56	11,030,019,004.49

Source: Minerals Management Service, Mineral Revenue Management, Reported Royalty Revenues, accessed online January 13, 2009, at <http://www.mrm.mms.gov/MRMWebStats/Home.aspx>.

1. Reported Royalty Revenue by Accounting Year – This data set represents all royalty data accepted in the MRM Financial System including adjusted royalty line transactions. This data is static and will not change. The “Accounting Year” or “acceptance date” approach has been used by MRM since its inception in 1982, because it represents all reported royalty revenues for a given reporting period (including revenues reported for prior periods) consistent with MRM’s financial reporting requirements. The data set identifies MRM’s mineral revenue collections that could be disbursed to appropriate recipients. However, the Accounting Year approach can impact data and/or trending.

2. Reported Royalty Revenue by Production Year – This data set provides a “snap shot” view of reported sales of mineral commodities, including adjustments for the current year, as of the report publication date. It offers a “point in time” view of the reported royalty revenue data sets that may be more useful for data analysis and/or trending purposes. However, because MRM processes royalty transactions in the MRM Financial System daily, this data set constantly changes. MRM captures this dynamic royalty reporting by assembling the subject data “as of” a specific date for a given reporting period. MRM will update the MRM Statistical Information web pages annually to reflect all revisions.

Source: Explanation of MRM Statistics, accessed online January 13, 2009, at <http://www.mrm.mms.gov/MRMWebStats/Explanation.aspx>.

Additional explanation from Kelly West, MMS:

The published 'Production Year' data covers October through September, and is not gathered until January or February of the following year. This differs from the depletion data that would include July through June and is gathered at September 30. At fiscal year end, August and September royalty data would not be received yet. Also, the published data is not gathered until January or February of the following year, in order to allow subsequent adjustments and late reporting to come in, in order to provide the most accurate picture possible. That is why you can see that the 'Production Year' data on the website states it is 'as of 2/21/08'. At that time, a snapshot is taken and published, but if the query were run again, the numbers would never be the same, due to constant adjustments being made by royalty payors. This 'Production Year' information is based upon sales month, but when we run it at Sept 30, or actually Oct 1, the amount used for depletion will differ from what is ultimately published, for the above reasons.

The royalty accrual is not included in the published information. It is a manual accrual required by GAAP in order to best estimate production in the current month, for which reporting will not be received until 1-2 months after the fact. The exchange event is deemed to be the point of production. So the published info includes only actually reported royalty information, coming in after production occurs.

The 'Accounting Year' published data includes any and everything that accepted in the system in the current fiscal year, regardless of sales month and which includes extensive prior period adjustments. That would not be what we recommend for the depletion basis. It is more useful when attempting to analyze disbursements, because the disbursements must generally be made by the month following the month of receipt. Also, it's static and will always be the same, because it includes everything accepted in the period - it is based upon 'accepted date' rather than sales month.

Attachment A – Example Royalty Revenue Reports (by Accounting Year and Production Year)

Reported Royalty Revenue by Category
Fiscal Year 2006
(Accounting Year)*

	American Indian	Federal Offshore	Federal Onshore	Total
Coal (ton)	\$ 88,909,744.01	\$	\$ 508,130,979.75	\$ 597,040,723.76
Gas (mcf)	340,612,131.63	3,160,028,663.49	2,265,291,662.71	5,765,932,457.83
NGL (gal)	8,102,620.40	127,898,443.62	149,486,657.46	285,487,721.48
Oil (bbl)	98,902,743.67	3,271,073,374.50	607,489,836.02	3,977,465,954.19
Other Royalties	42,326,017.03	(44,341,645.34)	107,621,420.41	105,605,792.10
Subtotal	\$ 578,853,256.74	\$ 6,514,658,836.27	\$ 3,638,020,556.35	\$ 10,731,532,649.36
Rents	1,195,119.89	224,006,816.08	60,122,681.87	285,324,617.84
Bonus		865,262,735.00	720,338,510.14	1,585,601,245.14
Other Revenues	8,536,513.59	2,839,550.43	2,493,458.76	13,869,522.78
Subtotal	\$ 9,731,633.48	\$ 1,092,109,101.51	\$ 782,954,650.77	\$ 1,884,795,385.76
Total	\$ 588,584,890.22	\$ 7,606,767,937.78	\$ 4,420,975,207.12	\$ 12,616,328,035.12

Reported Royalty Revenue by Category
Fiscal Year 2006
(Production Year as of 02/21/2008)*

	American Indian	Federal Offshore	Federal Onshore	Total
Coal (ton)	\$ 77,409,341.68	\$	\$ 512,035,056.31	\$ 589,444,397.99
Gas (mcf)	318,160,793.73	3,057,260,455.32	2,165,377,616.35	5,540,798,865.40
NGL (gal)	7,992,613.97	138,641,966.07	144,807,238.48	291,441,818.52
Oil (bbl)	95,485,346.39	3,577,000,191.62	631,102,841.18	4,303,588,379.19
Other Royalties	36,020,512.74	(29,036,715.51)	90,013,550.60	96,997,347.83
Subtotal	\$ 535,068,608.51	\$ 6,743,865,897.50	\$ 3,543,336,302.92	\$ 10,822,270,808.93
Non Revenue Volumes				
Rents	1,198,431.94	225,110,320.88	61,735,363.49	288,044,116.31
Bonus		862,838,750.00	673,496,634.29	1,536,335,384.29
Other Revenues	\$ 700,505.00	\$ 2,921,492.38	\$ 3,880,439.40	\$ 7,502,436.78
Subtotal	\$ 1,898,936.94	\$ 1,090,870,563.26	\$ 739,112,437.18	\$ 1,831,881,937.38
Total	536,967,545.45	7,834,736,460.76	4,282,448,740.10	12,654,152,746.31

Source: Minerals Management Service, Mineral Revenue Management, Reported Royalty Revenues, accessed online January 13, 2009, at <http://www.mrm.mms.gov/MRMWebStats/Home.aspx>.

Attachment A – Example Royalty Revenue Reports (by Accounting Year and Production Year)

Reported Royalty Revenue by Category
Fiscal Year 2005
(Accounting Year)*

	American Indian	Federal Offshore	Federal Onshore	Total
Coal (ton)	\$ 84,737,089.30	\$	\$ 457,494,476.31	\$ 542,231,565.61
Gas (mcf)	257,781,380.40	3,247,098,867.72	1,646,070,178.26	5,150,950,426.38
NGL (gal)	6,864,955.63	167,570,339.19	111,288,066.71	285,723,361.53
Oil (bbl)	76,908,323.94	2,118,772,810.28	398,640,058.74	2,594,321,192.96
Other Royalties	13,503,997.15	1,239,182.05	117,954,324.92	132,697,504.12
Subtotal	\$ 439,795,746.42	\$ 5,534,681,199.24	\$ 2,731,447,104.94	\$ 8,705,924,050.60
Rents	1,146,877.07	223,544,134.53	59,210,695.38	283,901,706.98
Bonus		564,936,380.00	733,206,133.61	1,298,142,513.61
Other Revenues	1,298,798.79	1,951,335.66	1,584,703.81	4,834,838.26
Subtotal	\$ 2,445,675.86	\$ 790,431,850.19	\$ 794,001,532.80	\$ 1,586,879,058.85
Total	\$ 442,241,422.28	\$ 6,325,113,049.43	\$ 3,525,448,637.74	\$ 10,292,803,109.45

Reported Royalty Revenue by Category
Fiscal Year 2005
(Production Year as of 02/21/2008)*

	American Indian	Federal Offshore	Federal Onshore	Total
Coal (ton)	\$ 87,501,704.33	\$	\$ 459,222,871.69	\$ 546,724,576.02
Gas (mcf)	284,808,958.70	3,284,206,728.25	1,785,984,355.57	5,355,000,042.52
NGL (gal)	6,904,387.46	168,921,431.29	119,627,879.72	295,453,698.47
Oil (bbl)	81,356,845.17	2,097,114,219.27	420,668,560.36	2,599,139,624.80
Other Royalties	20,134,650.83	9,200,279.59	181,656,545.63	210,991,476.05
Subtotal	\$ 480,706,546.49	\$ 5,559,442,658.40	\$ 2,967,160,212.97	\$ 9,007,309,417.86
Non Revenue Volumes				
Rents	1,283,019.79	225,121,557.77	56,276,336.33	282,680,913.89
Bonus		564,936,380.00	714,699,271.10	1,279,635,651.10
Other Revenues	\$ 3,266,858.91	\$ 2,752,527.68	\$ 4,445,043.59	\$ 10,464,430.18
Subtotal	\$ 4,549,878.70	\$ 792,810,465.45	\$ 775,420,651.02	\$ 1,572,780,995.17
Total	485,256,425.19	6,352,253,123.85	3,742,580,863.99	10,580,090,413.03

Source: Minerals Management Service, Mineral Revenue Management, Reported Royalty Revenues, accessed online January 13, 2009, at <http://www.mrm.mms.gov/MRMWebStats/Home.aspx>.

[This page intentionally left blank.]

Issue Paper No. 5: Reporting Changes in Assumptions

December 2008 Draft ED Requirements

The December 2008 draft of the revised exposure draft (ED) on *Accounting for Federal Oil and Gas Resources* contained the following proposed requirements related to reporting gains and losses from changes in long-term assumptions on the statement of net cost.

41. For estimates that are developed using present value, component entities should display gains and losses from changes in **long-term assumptions** used to measure assets and liabilities for oil and gas as a separate line item or line items on the statement of net costs as required for pensions, ORB, and OPEB in SFFAS 33.¹ (*Staff will explore the need for additional guidance on what would constitute a change in assumption for oil and gas vs. true gains and losses.*)

Basis for Conclusions Discussion

Reporting the Gains and Losses from Changes in Assumptions and Selecting Discount Rates

- A49. SFFAS 33, *Pensions, Other Retirement Benefits, and Other Postemployment Benefits: Reporting the Gains and Losses from Changes in Assumptions and Selecting Discount Rates and Valuation Dates*, requires that gains and losses from changes in long-term assumptions used to estimate federal employee pension, other retirement benefit (ORB), and other postemployment benefit (OPEB) liabilities should be displayed on the statement of net cost separately from other costs. This display provides more transparent information regarding the underlying costs associated with certain liabilities. SFFAS 33 also provides standards for selecting the discount rate assumption for pension, ORB, and OPEB liabilities.
- A50. SFFAS 33 does not preclude entities from displaying or disclosing any information about the effect of changes in any assumptions with regard to other types of activities. The original SFFAS 33 ED had proposed a broad scope; however, although in principle a broader application was desirable, the Board decided to limit the standard to federal employee pension, ORB, and OPEB liabilities. This decision was based on the Board's desire to address more immediately its primary concern, which is to display the effect of assumption changes on employee compensation liabilities. Respondents had requested more guidance regarding how the standard would apply to other long-term assumptions; the Board believed that developing additional guidance would significantly delay implementation of SFFAS 33.
- A51. The Board believes that it would be appropriate to apply the guidance in SFFAS 33 to long-term assumptions about oil and gas.

¹ [Footnote 12:] See SFFAS 33, paragraphs 19 through 27 for additional guidance.

FASAB Staff Analysis and Recommendation

As promised in par. 41 of the December 2008 draft of the revised ED, staff explored the need for additional guidance on what would constitute a change in assumption for oil and gas vs. true gains and losses by reviewing the requirements of SFFAS 33 and discussing changes in oil and gas estimates with DOI personnel.

What contributes to changes in oil and gas estimates?

“True” gain or loss as a result of normal operations of oil and gas (“Experience”)

- I. **Changes in estimated quantity** – The estimated quantity can be revised periodically for any number of factors that affect the overall amount of resources that will be extracted from the ground, including:
 - Discoveries (extensions, new field discoveries, and new reservoir discoveries in old fields)
 - Acquisitions
 - Revisions and adjustments
 - Improved technology (ability to extract more oil and gas at a lower cost)
 - Royalty-free annual volumes (the quantity that falls under the royalty relief provisions each year)
 - Sales
 - The geological make-up of the earth
 - The depth of the water or the depth of the wells for offshore wells
 - The uncertainties of each well
 - Proved reserves under federal lands as a proxy of federal production to total nationwide proved reserves
 - Affect on quantity caused by changes in supply and demand which can be affected by various activities (e.g., the permitting process for exploration, development, and production activities; the lessee’s available budget; other projects the lessee is focusing on; production incentives provided by the federal government)

- II. **Changes in estimated price** – The estimated price can be revised periodically for any number of factors that affect the overall valuation of resources that will be extracted from the ground, including:
 - Increases / decreases in oil and gas prices (price volatility)
 - Affect on price caused by changes in supply and demand which can be affected by various activities (e.g., the permitting process for exploration, development, and production activities; the lessee’s available budget; other projects the lessee is focusing on; production incentives provided by the federal government)
 - Transportation allowances

- Projection of how oil and gas proved reserves will be produced over time (production decline curve)

III. Changes in established royalty rate – Royalty rates can periodically be revised by legislation.

Changes in assumptions that do not result in a “true” gain or loss (“Assumption Changes”)

- Discount rates
- Inflation rates

Recommendation:

Component Entity

FASAB staff recommends that the component entity responsible for collecting royalties should disclose the following reconciliation of beginning and ending estimated petroleum royalties asset balances in the notes to the financial statements:

Beginning asset balance	\$XX,XXX
Revaluation Gain / Loss Due to Changes in:	
Quantity	XXX
Price	(XX)
Royalty Rates	XX
Assumptions	
Discount Rate	X,XXX
Inflation Rate	XXX
Less:	
Depletion	(XXX)
Sale of future royalty streams	(XX)
Ending asset balance	\$XX,XXX

The reconciliation should provide all material components of the changes in the estimated petroleum royalties asset consistent with the components identified in the table immediately above, if applicable. Additional sub-components may be presented. The line item for revaluation gains and losses should be broken out into sub-components for changes in quantity, price, royalty rates, and assumptions, if applicable.

In addition, FASAB staff recommends adding the following requirement for RSI to communicate the significant causes of the change in estimated petroleum royalties:

43. The component entity responsible for reporting the federal government’s estimated petroleum royalties on its balance sheet should provide the following as RSI:

- b. An explanation of the significant components of the change in estimated petroleum royalties from one year to the next, the amounts associated with each type of change, and the reasons for the changes. The reasons should be explained as briefly as possible without detracting from understanding. Significant components of the change in estimated petroleum royalties include, but are not limited to, changes in quantity, price, royalty rates, discount rates, and inflation rates.

Governmentwide Entity

FASAB staff recommends the following requirement be added for the governmentwide reporting entity:

46. The governmentwide entity should display gains and losses from changes in assumptions as a separate line item or line items on the statement of net cost after a subtotal for all other costs and before total cost. See the pro forma illustration in Appendix B of SFFAS 33.

Excerpts from SFFAS 33, Pensions, Other Retirement Benefits, and Other Postemployment Benefits: Reporting Gains and Losses from Changes in Assumptions, and Selecting Discount Rates and Valuations Dates

Display

Component Entities

19. Component entities should display gains and losses from changes in long-term assumptions used to measure liabilities for federal civilian and military employee pensions, ORB, and OPEB, including veterans' compensation, as a separate line item or line items on the statement of net costs. See the pro forma illustration in Appendix B.
20. Selecting the gains and losses to display from changes in individual pension, ORB, and OPEB liability assumptions to be displayed on the statement of net cost requires judgment. The preparer should consider quantitative and qualitative criteria. Acceptable criteria include but are not limited to quantitative factors such as the percentage of the reporting entity's cost that resulted from the gain or loss and the size of the gain or loss relative to the liability; and qualitative factors including whether the gain or loss would be of interest to decision-makers and other users. Nothing in this standard should be construed to preclude an entity from displaying gains or losses from changes in short-term assumptions.
21. Pursuant to SFFAS 5, some component entities report the liability and expense for pensions, ORB, or OPEB, while other component entities report only **normal (or service) cost**.⁷ The Office of Personal Management is an example of the former with respect to the Federal Employees Retirement System (FERS), and federal component entities with employees participating in FERS are examples of the latter. Component entities that report pension, ORB, or OPEB liabilities should display a discrete line item for gains and losses from changes in assumptions on its statement of net cost when the conditions in paragraphs 19-20 above are met. Component entities reporting only the normal or service cost should not display such gains and losses.
22. Component entities should disclose in notes to the financial statements the following reconciliation of beginning and ending pension, ORB, and OPEB liability balances:

⁷ The terms "employer entity" and "administrative entity" are used in SFFAS 5 to distinguish between entities that employ federal workers and thereby incur the employee costs, including pension cost, and those that are responsible for managing and/or accounting for the pension or the other employee plan. For example, entities that receive "salaries and expense" appropriations are employer entities, while the Office of Personnel Management (OPM) is an administrative entity because it administers the civilian retirement benefit plans. See especially SFFAS 5, pars. 71-2 and 88. An entity may be both an employer entity and an administrative entity, for example, when it, rather than OPM, administers a pension plan for its employees. In such instances, that entity would be responsible for reporting gains and losses from changes in assumptions if the conditions in paragraph 19-20 are satisfied.

Excerpts from SFFAS 33, contd.

Beginning liability balance	\$X,XXX
Expense:	
Normal cost	XX
Interest on the liability balance	XX
Actuarial (gain)/loss:	
From experience	XX
From assumption changes	XX
Prior service costs	X
Other	(X)
Total expense	XXX
Less amounts paid	(XX)
Ending liability balance	\$X,XXX

23. This reconciliation must provide all material components of pension, ORB, or OPEB expense consistent with the components identified in the table immediately above, if applicable. Additional sub-components may be presented. The line item for **actuarial gains and losses** should be broken out into the sub-components “from experience” and “from assumptions changes.” Significant pension, ORB, and OPEB programs should be presented individually in a separate column along with an “all other” column, if applicable, and a “total” column for each line item.
24. Component entities that report pension, ORB, or OPEB liabilities should disclose the information required in paragraph 22. Component entities reporting only the normal or service cost should not disclose the information required in paragraph 22.
25. Component entities holding non-Treasury securities as assets to fund their pension, ORB, or OPEB programs should disclose the rates of return, specific maturities, and allocation by type (stocks, bonds, etc.) of such assets.

Governmentwide Entity

26. The governmentwide entity should display gains and losses from changes in assumptions as a separate line item or line items on the statement of net cost after a subtotal for all other costs and before total cost. See the pro forma illustration in Appendix B.
27. The governmentwide entity should disclose in the notes to the financial statements a reconciliation consistent with information required in paragraph 22 above for pension, ORB, and OPEB liabilities. At a minimum, reconciliations for liabilities classified as civilian, military, and veterans compensation must be presented. See Appendix C for an example.

* See the glossary for this standard’s definition of “normal cost.”

Excerpts from SFFAS 33, contd.

Appendix B: Pro Forma Statement of Net Cost Displaying Separate Line Item for Gains and Losses Due to Changes in Assumptions

Component Entity: Pro forma *Statement of Net Cost for the Year Ended September 30, 2007*

	2007 (billions)
ABC Program	
ABC expenses	\$ 223
Less: exchange revenue	<u>24</u>
Net expense before gain/loss from changes in assumptions	199
(Gain)/loss on assumption changes:	
Discount rate assumption	<u>200</u>
Other assumptions	<u>(50)</u>
Net (gain)/loss on assumption changes	150
Net cost	\$349

Governmentwide Entity: Pro Forma *Statements of Net Cost for the Year Ended September 30, 2007*

	Gross Cost	Earned Revenue (billions)	Net Cost
ABC Agency.....	\$ 199	\$ 24	\$ 223
OPM.....	***	**	***
DVA.....	***	**	***
XYZ.....	***	**	***
* * *			
Other agencies.....	<u>146</u>	<u>92</u>	<u>54</u>
Cost before gains/losses from changes in assumptions	3,060	226	2,834
Less: loss (plus gain) from changes in assumptions:			
ABC.....	<u>150</u>	<u>0</u>	<u>150</u>
OPM.....	<u>100</u>	<u>0</u>	<u>100</u>
DVA.....	<u>110</u>	<u>0</u>	<u>110</u>
Total cost	\$ 3,420	226	\$ 3,194

[This page intentionally left blank.]

Issue Paper No. 6: Recognition of Gains/Losses on DOI SoNC and Liability for Revenue to be Distributed to Federal Entities

December 2008 Draft ED Requirements

Recognition of Gains/Losses on DOI SoNC

The December 2008 draft of the revised exposure draft (ED) on *Accounting for Federal Oil and Gas Resources* contains the following proposed requirements related to recognizing gains and losses on the statement of net cost that were carried forward from the May 2007 ED, revised only to remove the reference to detailed guidance for the calculation of the value of estimated petroleum royalties and update the paragraph numbers.

38. The estimated petroleum royalties asset shall be valued at the end of each year for financial statement reporting.
39. The calculated value of estimated petroleum royalties at year-end shall be compared to the existing book value of the estimated petroleum royalties asset. If the calculated value of the estimated petroleum royalties asset at year-end is greater than the book value,^[1] the book value shall be increased to the new estimate and a gain shall be recorded on the statement of net cost. If the calculated value of the estimated petroleum royalties asset at year-end is less than the book value, the book value shall be decreased to the new estimate and a loss shall be recorded on the statement of net cost.
40. In addition, if the calculated value of the estimated petroleum royalties asset at year-end is greater or less than the book value, the liability for revenue distributions to others shall be increased or decreased to the amount expected to be distributed.^[2] If the revaluation resulted in a net gain, the liability and a corresponding expense and/or transfer-out for the revenue distributions to others shall be increased by an amount equal to the amount of the gain designated to be distributed to others, e.g., the states, the general fund of the U.S. Treasury and other federal agencies. If the revaluation resulted in a net loss, the liability and a corresponding expense and/or transfer-out for the revenue distributions to others shall be decreased by an amount equal to the amount of the loss, which will reduce future distributions to others.^[3]

Liability for Revenue to be Distributed to Federal Entities

The December 2008 draft of the revised exposure draft (ED) on *Accounting for Federal Oil and Gas Resources* contains the following proposed requirements related to recognition of the liability for revenue to be distributed to others. Paragraph 30 was carried forward from the May 2007 ED, revised only to include a reference to present value and update the paragraph number. Pars. 29 and 31 were added to further clarify the requirements.

29. Upon collection, the majority of the federal government's estimated petroleum royalties from the production of federal oil and gas proved reserves are distributed

¹ [Footnote 9:] The estimated petroleum royalties beginning balance would have been reduced by the amount expensed on the statement of net cost.

² [Footnote 10:] For example, the average annual share of the revenue distributed to others over the preceding twelve (12) months may be an acceptable basis to estimate future distributions. Other methodologies may be acceptable.

³ [Footnote 11:] An adjustment to "expense" would be made for distributions related to non-federal entities while an adjustment to "transfer-outs" would be made for distributions related to federal entities.

to states, other federal agencies, and the general fund of the U.S. Treasury in accordance with legislated allocation formulas. The legislated allocation formulas constitute a present obligation of the component entity that is responsible for collecting royalties to provide assets to another entity, and the underlying legislation identifies the conditions under which these distributions will be made.

30. A liability for revenue distributions to others shall be recognized on the balance sheet of the component entity that is responsible for collecting royalties in conjunction with the recognition of an asset for estimated petroleum royalties. The amount of the liability shall be estimated based on the present value of the royalty share of the federal proved oil and gas reserves designated to be distributed to others, e.g., the states, the general fund of the U.S. Treasury and other federal agencies. For example, the average annual share of the revenue distributed to others over the preceding twelve (12) months may be an acceptable basis for estimating petroleum royalties to be distributed to others. Other methodologies may be acceptable.
31. The net effect of recognizing an asset and establishing a liability at the beginning of the reporting period would be a change in accounting principle that increases the entity's net position.

Board Member Concern about Current Draft ED Requirements Regarding Gain/Loss

At the December 2008 board meeting, Mr. Jackson stated that he does not believe that liabilities for collections to be distributed to others should roll through the statement of net cost. He thinks it is inappropriate for the gains and losses on revaluation to show up on DOI's financial statements. He sees where the gains and losses recognized on the statement of net cost are offset by a transfer out on the statement of changes in net position, but he does not believe that the agency should be saddled with reporting those gains and losses since they are not true gains and losses for DOI.

DOI Response to Current Draft ED Requirements Regarding Liability

In response to pro forma entry number one on the ED view and present value (PV) view field test questionnaires, the field test team stated that:

“It must be noted that currently when recording the corresponding liabilities for end of period assets, MMS employs an agreed-upon procedure whereby we estimate the percentages allocable to our three largest recipients; U.S. Treasury, Reclamation Fund and the States. In the proposed ED models, due to the magnitude of the asset value, even the estimated 1% that MMS receives in annual appropriations becomes material. This creates a situation where each recipient will require a liability entry based on some estimation method, and each designated federal recipient will be required to record a corresponding receivable and transfer in their statements, with eliminations between entities to prevent double counting government wide. You will see later in the text that any adjustment made to the asset results in an effect upon the recipient which will require an entry. **This becomes especially critical at quarter ends and at fiscal year end, where late adjustments required to accruals that are deemed related to oil and gas revenue (and hence, depletion) will also require late adjustments by all downstream recipients, thus significantly hampering entities ability to meet accelerated financial reporting due dates and potentially giving rise to audit findings.**”

DOI staff has communicated to FASAB staff several times that they recommend not recording a liability for revenue to be distributed to other federal entities and absorbing the full asset value themselves for cost/benefit reasons.

FASAB Staff Analysis and Recommendation

There are two separate but related issues outlined in the above narrative. The first issue is whether it is appropriate for DOI to recognize the gains and losses on revaluation of estimated petroleum royalties on its agency statement of net cost. The second issue is whether it is cost-beneficial for DOI to record a liability entry for each federal agency to which revenue is to be distributed, and for each federal receiving agency to recognize the related receivable and all of the subsequent revaluation adjustments.

Issue 1 – Recognizing revaluation gains and losses on DOI SoNC

The first issue is addressed in the “Entity Concept” discussion within pars. 11 – 14 of SFFAC 5, *Definitions of Elements and Basic Recognition Criteria for Accrual-Basis Financial Statements*:

11. The federal government is composed of component entities that control, manage, or are otherwise accountable for the government’s assets and may be authorized to incur liabilities. Component entities include departments, independent agencies, and government corporations, as well as their agencies, bureaus, offices, administrations, corporations, and other organizational units. **An item that meets the definition of an element of the federal government is also an element of a component entity.** It is recognized in the component entity’s accrual-basis financial statements provided it meets the basic recognition criteria and the additional considerations for recognition decisions. [emphasis added]
12. Sometimes a question may arise as to which component entity should report a particular item. Typically, a review of the authorizing legislation establishing a government program or activity, the appropriations act funding it, and related federal laws, regulations or other executive issuances clearly identifies one component entity as having a comprehensive relationship to the program or activity. That is, the component entity is responsible and accountable for receiving, controlling, managing, and utilizing government assets or incurring liabilities on behalf of the government in performing operations related to the program or activity. When a component entity has such a comprehensive relationship, the assets and other elements involved should be reported by that component entity.
13. When no component entity has a comprehensive relationship to a government program or activity, the assets and other elements involved should be reported by the component entity most responsible for managing them. For example, assume that two component entities support a single program to which neither has a comprehensive relationship. If one of the component entities has acquired and has some control over a government asset but the other component entity presently manages and utilizes the asset as part of its routine operations, the second component entity should report the asset. In other circumstances, a component entity’s management responsibilities may be limited to, for example, collecting monies owed to the federal government and depositing them in the U.S. Treasury. Although the component entity has no authority or responsibility to retain or use the monies collected, it should report the assets and other elements involved in the collection activity.
14. While **items that meet the definition of an element from the perspective of the federal government are assigned to component entities**, some items recognized in the accrual-basis financial statements of component entities are not recognized in the consolidated financial statements of the federal government because they do not meet definitions of elements from the perspective of the federal government. Instead, they are items that would meet element definitions from the component entity perspective and are treated as such by the component entity. For example, component entities may exchange services for a fee and recognize the resulting intra-governmental assets, liabilities, and related elements in their financial

statements. However, intra-governmental items offset each other when the government is viewed as a whole and are eliminated in preparing the government's consolidated financial statements. [emphasis added]

In developing SFFAC 5, the board intended that items that are included within the consolidated financial report of the U.S. Government (CFR) be derived from the agency financial statements. As noted in pars. 11 and 14 (see bold text), items that meet the definition of an element from the perspective of the federal government are assigned to component entities.

It has been established that DOI is the component entity that will record the estimated petroleum royalties asset because DOI has a comprehensive relationship with the royalty revenue program through its Minerals Management Service and is most closely responsible for managing it.

SFFAC 5 defines a revenue as an inflow of or other increase in assets, a decrease in liabilities, or a combination of both that results in an increase in the government's net position during the reporting period. SFFAC 5 defines an expense as an outflow of or other decrease in assets, an increase in liabilities, or a combination of both that results in a decrease in the government's net position during the reporting period (SFFAC 5, pars. 52 and 53).

Gains and losses are considered subsets of revenues and expenses, rather than distinct elements, just as capital assets and financial assets are considered subsets of assets (SFFAC 5, par. 56). Since it has already been concluded that DOI is the appropriate component entity to recognize the asset, and revenues and expenses are defined as changes in assets and liabilities, staff believes it is appropriate for the gains and losses from revaluation of estimated petroleum royalties to be reported in the statement of net cost of DOI (the component entity most closely responsible for managing royalty revenue).

Issue 2 – Recognizing a liability for revenue to be distributed to federal entities

In developing the ED, the board considered and agreed that an offsetting liability should be recognized in conjunction with the recognition of an asset for estimated petroleum royalties. The board believed an offsetting liability should be recognized because nearly all of the revenue from royalties, lease sales, and rent are ultimately distributed to the general fund of the U.S. Treasury, other federal agencies, and the states. As the proceeds are distributed, the liability would be reduced. In addition, upon consolidation, the portion of the liability related to other federal agencies and the general fund of the U.S. Treasury would be eliminated so that the balance sheet for the government as a whole reports only the liability for amounts allocated to non-federal entities. The board believed that if a liability was not established, the component entity's and the federal government's net position would be overstated.

Liability entries would be required for several federal and nonfederal entities – other Department of the Interior entities (Minerals Management Service, Bureau of Reclamation, National Park Service Conservation Funds, Bureau of Land Management, and Fish and Wildlife Service); Other Federal Agencies (Department of the Treasury, Department of Energy, Department of Agriculture, and Department of the Commerce); Indian Tribes and Agencies; and States and others.

Presently, DOI recognizes a year-end royalty accrual for custodial receivables and distributions payable that represents the current period activity anticipated to be received in the subsequent period. The balance is estimated based on an analysis of the last twelve months of royalty activity, and recent events, such as significant settlements due in September. DOI calculates and recognizes the liability for only their three largest recipients—Treasury, Reclamation and the States—based upon an average of the prior months' distributions to them for the year. The other recipients are not considered material enough to require that degree of detail. However if

the ED requires that a liability be recorded for the entire estimated petroleum royalties, every recipient would likely be material due to the magnitude of the asset, and DOI would have to recognize a liability for each entity.

For example, DOI makes distributions to the Department of Energy (DOE) that are used to fill the Strategic Petroleum Reserve (SPR), which is frequently authorized, deauthorized, filled to authorized capacity and stopped, or increased. At year-end, the SPR amounts vary widely. As a result, it would be extremely difficult for DOI to reliably estimate the liability for future royalty distributions to DOE for their portion of estimated petroleum royalties because there are some years when DOE receives a large portion of distributions, some years when their portion is quite small, and some years when it is zero.

Conceptually, it would be appropriate for DOI to record a liability for the revenue to be distributed to all federal and non-federal parties. However, in its response to the field test questionnaires, the DOI field test team notes that each designated federal recipient would be required to record a corresponding receivable and transfer in their statements, with eliminations between entities to prevent double counting government wide. The field test team notes that this accounting becomes especially critical at quarter-ends and at fiscal year-end, where late adjustments required to accruals that are deemed related to oil and gas revenue will also require late adjustments by all downstream recipients, thus significantly hampering entities' ability to meet accelerated financial reporting due dates and potentially giving rise to audit findings.

Recognizing that the federal government's current environment results in a continuing strain on resources, the board has become even more sensitive to developing accounting requirements that serve to provide meaningful information to financial statement users while trying to avoid requirements that are complied with merely for the sake of compliance. The board has initiated a project to evaluate current standards to identify areas where benefits are limited.

The draft ED requirements would result in each of the receiving federal entities recognizing an accounts receivable and a transfer in their financial statements for the initial asset entry. Then, as the asset is subsequently revalued or adjusted by DOI or its auditors, the receiving federal entities would need to adjust their accounts receivable and transfer accounts. In addition, the intragovernmental elimination entries would need to be adjusted as well. This would be a lot of last minute adjusting for amounts that would be eliminated from the CFR. However, if the receivable entries were not made, the receiving entities would not be including these assets in their financial statements. The question becomes "What is the value of having the federal component entities record the receivable and transfer in their financial statements?"

Accounts receivable arise from claims to cash or other assets (SFFAS 1, par. 40). The purpose of recognizing accounts receivable for accrual-basis accounting is to recognize a resource that embodies economic benefits or services in the period that it becomes measurable (SFFAC 5, pars. 5 and 18). While the board has decided that the estimated petroleum royalties asset upon which the receivable would be based can be reasonably estimated, it is doubtful that the federal receiving entity management would find much decision-useful information with the recognition of a receivable that would be extremely volatile and could not be relied upon for short or long-term budget decisions. In addition, it is doubtful that the financial statement users would find more value in recognition of a receivable on the face of the financial statement as opposed to a disclosure of an estimated amount in the notes to the financial statements. On the contrary, revaluations of the asset that result in large inflows or outflows to the receiving entity in any given year would raise eyebrows and require a detailed explanation to satisfy the user.

In addition to the above considerations, MMS informed FASAB staff that the Department of the Treasury stated that they would not recognize a receivable for the portion that is distributed to the Treasury General Fund. Therefore, until the accounting for the Treasury General Fund is assigned, MMS would not recognize a liability for the portion of the estimated petroleum royalties to be distributed to the Treasury General Fund, which accounts for approximately half of MMS' annual distributions.

Recommendation: Retain the requirements in pars. 38 – 40 [from the December 2008 revised draft ED – see paragraphs 37 – 39 in the current revised draft ED at Tab F-1] for gains and losses from revaluation of estimated petroleum royalties to be reported in the statement of net cost of DOI (the component entity most closely responsible for managing royalty revenue). Revise the requirements in 29 – 31 [from the December 2008 revised draft ED – see paragraphs 27 – 30 in the current revised draft ED at Tab F-1] so that only a liability for revenue to be distributed to non-federal entities (e.g., states) is required to be recognized. Add a requirement that each federal receiving entity disclose in the notes to its financial statements its relationship with the royalty revenue program and DOI's estimate of the total amount of estimated petroleum royalties to be distributed to it.

Tab F-3

**Appendix 2 – Summary of
May 2007 ED Requirements
and Recommended
Response to Field Test
Comments**

[This page intentionally left blank.]

Summary of May 2007 ED Requirements

<u>Proposed Standard</u>	<u>Par.</u>	
I. Asset		
Calculate asset value of oil and lease condensate, natural gas plant liquids, and dry gas.	6 - 8	<div style="border: 1px solid black; padding: 5px;"> <p style="text-align: center;">BS</p> <p>Asset Est Petr Royalties</p> <p>Liability Rev Distr. to Others</p> <p>Net Position Prior Period Adjustment - Change in Accounting Principle</p> </div>
<i>Basic Formula:</i> Regional Quantity X Regional Price X Regional Average Royalty Rate = Estimated Petroleum Royalties	16	
All types of crude oil streams and gravity bands are aggregated for this calculation.	9	
Regions used shall be collaboratively developed by entities involved in oil and gas resource activities.	17	
Asset should be valued at the end of each year and gains or losses as a result of revaluation should be recorded on SoNC.	27 - 28	
II. Liability		
Calculate liability for royalty share of proved oil and gas reserves designated to be distributed to others.	20	<div style="border: 1px solid black; padding: 5px;"> <p style="text-align: center;">SONC</p> <p>Exchange Revenue Bonus Bid Rent Revenue Royalties</p> <p>Expenses Depletion Expense Net gain or loss from sale of royalty rights and revaluation</p> </div>
The net effect of recognizing an asset and establishing a liability at the beginning of the reporting period would be a change in accounting principle that increases the entity's net position.	ES	
Recognize a liability and corresponding expense and/or transfer out for the bonus bid and rent revenue to be distributed to others.	22	
III. Revenue and Depletion		
Bonus bid and rent revenue recognized as exchange revenue on the SoNC (also corresponding expense).	22	<div style="border: 1px solid black; padding: 5px;"> <p style="text-align: center;">SONC</p> <p>Exchange Revenue Bonus Bid Rent Revenue Royalties</p> <p>Expenses Depletion Expense Net gain or loss from sale of royalty rights and revaluation</p> </div>
Royalties recognized as exchange revenue (also corresponding depletion expense and reduction of asset).	23	
IV. Disclosures		
Value of future royalty rights identified for sale disclosed in the notes (no reclassification on the balance sheet).	24	<div style="border: 1px solid black; padding: 5px;"> <p style="text-align: center;">SONC</p> <p>Exchange Revenue Bonus Bid Rent Revenue Royalties</p> <p>Expenses Depletion Expense Net gain or loss from sale of royalty rights and revaluation</p> </div>
Value of future rights should be calculated based on the specific field to be sold (not region).	25	
Extensive component entity disclosures.	31	
Extensive component entity RSI.	32	
CFR Disclosures	33	
Fiduciary Disclosures	34	

ES = Executive Summary

Summary of May 2007 ED Requirements (contd.)

<u>Proposed Standard</u>	<u>par.</u>
V. Valuation Guidance	
Based on annual survey conducted by the EIA - "The most recent survey conducted by the EIA, issued no more than twelve (12) months before the end of the reporting period..."	38
Proved lease condensate reserves are to be included with the proved oil reserves.	38
Detailed valuation guidance provided in paragraphs 37 - 45.	37-45
VI. Effect on Existing Standards	
Replaced example in SFFAS 7, par. 45, "rents and royalties on the Outer Continental Shelf" with "revenues from the auction of the radio spectrum."	46
Deleted pars. 275, 276, and 277 of SFFAS 7 from Appendix B: Guidance for the Classification of Transactions.	47
VII. Effective Date	
Effective for periods ending after 9/30/2009.	48

Recommended Response to ED View Field Test Team Comments / Methodology

#	ED View Field Test Team Comments / Methodology	ED FT pg.	Recommended Response
1	Additional entries would be made in practice. Also, greater degree of details and certain reclassifications would occur in practice.	2	Add similar language to Appendix C of the ED.
2	Effect on pars. 16, 18, 37, 38, 39, 42, and 45: oil and lease condensate should be computed separately and then summed because their average unit price and rate are different.	3	Eliminate detailed guidance on how to calculate asset value, including component calculations; allow for flexibility.
3	Effect on pars. 8, 11, 14, 16, 18, 37, 38, 41, 44, and 45: wet and dry gas should be computed separately and then summed together.	3 - 5	Eliminate detailed guidance on how to calculate asset value, including component calculations; allow for flexibility.
4	Regions should be divided to a greater degree than was done in the field test to better reflect price differentials in different basins and regions.	4	Comment noted but no change proposed. The requirements proposed in the ED give general guidance on the selection of regions and do not preclude further breakdown. (par. 18)
5	Portion of proved reserves under federal domain not currently published by EIA. Test team created a methodology.	4	Eliminate detailed guidance on how to calculate asset value, including specific source of information; allow for flexibility.
Asset Value			
6	Queried MRM royalty reports for 12 sales (production) months in 2005, including adjustments through September 2007.	4	Eliminate detailed guidance on how to calculate asset value, including specific source of information; allow for flexibility.
7	Obtained EIA report of total nationwide estimated proved reserves.	4	
8	Estimated the federal portion of onshore proved reserves by using a ratio of 2005 onshore estimated production nationwide published by EIA, compared to 2005 total production volume from federal leases reported to MRM on royalty reports. The ratio of federal to total 2005 production then became a proxy for the ratio of federal proved reserves to total proved reserves reported by EIA.	4	
9	Utilized the existing royalty reported data for sales months in calendar year 2005 to aid in computing the estimated quantity. (In practice, would base quantity on the preceding 12 sales months royalties reported for which royalty production data is available or July through June when measured at September 30).	5	

#	ED View Field Test Team Comments / Methodology	ED FT pg.	Recommended Response
10	Average royalty rates were computed by dividing the total regional royalty value by the total regional sales value by commodity category for sales months in calendar year 2005.	6	
11	Average unit prices were similarly derived by dividing the total regional sales value by the total regional sales volume.	6	
12	The asset value was computed by simply multiplying average rate X average unit price X estimated quantity for each region and commodity category.	6	
13	The totals were then summed to arrive at the total estimated value to capitalize.	6	
14	Inserted "and the other federal component entities for their allocable share of the related asset" into narrative of pro forma entry 1.	8	Delete federal receiving entity requirement to record receivable. See number 15 below and Issue Paper No. 6 at Appendix 1.
15	When recording the corresponding liabilities for end of period assets, MMS estimated the percentages allocable to its three largest recipients; U.S. Treasury, Reclamation Fund and the States. In the proposed ED models, due to the magnitude of the asset value, even the estimated 1% that MMS receives in annual appropriations becomes material. This creates a situation where each recipient will require a liability entry based on some estimation method, and each designated federal recipient will be required to record a corresponding receivable and transfer in their statements, with eliminations between entities to prevent double counting government wide. This becomes especially critical at year end, where late adjustments required to accruals that are deemed related to oil and gas revenue (and hence, depletion) will also require late adjustments by all downstream recipients, thus significantly hampering entities ability to meet accelerated financial reporting due dates and potentially giving rise to audit findings.	9 - 10	Revise the requirements so that only a liability for revenue to be distributed to non-federal entities (i.e., states) is required to be recognized. Add a requirement that each federal receiving entity disclose in the notes to its financial statements its relationship with the royalty revenue program and DOI's estimate of the total amount of estimated petroleum royalties to be distributed to it. See Issue Paper No. 6 at Appendix 1.
Depletion Expense			
16	Revenue earned by the collecting entity generally consists of amounts reported or billed, cash for which no royalty report has been received (unmatched cash), and amounts accrued as estimates. There is not a simple means at this time to obtain detail which reconciles to the general ledger and financial statements, of all components of earned revenue specifically related to oil and gas and more specifically related to offshore vs. onshore leases.	13	No change to the draft ED requirements proposed. The depletion approach in the ED was not devised to show the "true" effect on the asset during the period since the quantity gets adjusted again at year-end as part of the revaluation. Rather, the depletion approach was an attempt to ensure that the only bottom line effect on MMS' statement of net cost was the net gain / loss that resulted from quantity and value differences from one year to the next. In other
17	The field test team's recommended alternative is to record depletion based upon royalty reporting lines received and accepted for the preceding 12 sales months available at fiscal year end; July through June (received through August, fully available in September). This would preclude the need to include estimates in the depletion calculations and would represent a realistic value of true asset depletion based on actual royalty reporting.	14	

#	ED View Field Test Team Comments / Methodology	ED FT pg.	Recommended Response
18	Under the field test team's recommended alternative, revenue earned would not be a perfect match in the fiscal year, but the field test team believes that in this case it should not, because depletion in the current year should not be linked to prior adjustments not related to the current year.	14	words, the depletion approach in the ED is to “match” depletion expense with revenue recognition. A methodology can be developed to estimate the portion of unmatched cash, adjustments, and accruals to be allocated to oil and gas. (See Issue Paper No. 4 at Appendix 1 for a more detailed discussion on depletion expense.)
19	Another alternative proposed by the field test team would be to record depletion based solely upon all royalty lines received and accepted during the fiscal year, excluding all accruals and regardless of sales month. Again, revenue earned would not be a perfect match in the fiscal year, because accruals would be excluded.	15	
	<i>Issues:</i>		
20	-Components that comprise "royalty revenue earned"	13	
21	-Whether or how to include estimates such as the high-level royalty accrual	13, 16 - 17	
22	-Relationship of revenue to depletion expense (e.g., relationship between revenue recorded in the current FY for royalty reporting adjustments made to prior years and CY depletion expense)	13	
23	-Ability to obtain information at level of detail required	13	
24	-Upward or downward adjustments related to prior royalty reporting included in current year earned revenue.	14	
25	-Allocating line level royalty revenue that includes rejected lines with missing detail	15	
26	Prior to DOI conducting the field study, previous discussions with FASAB Staff indicated that in order to provide matching of royalty revenue earned in the fiscal year, the royalty accrual would be included in the 'revenue earned' that would be offset by depletion expense, because the accrual estimates production in the current month for which royalty reports will not be yet be received. Also, it was discussed that revenue recognition overall should remain consistent, and that revenue earned in the fiscal year, regardless of sales (production) month and subsequent adjustments, would still apply. Accordingly, the text in [par.] #23 and throughout the Statement was going to be revised to include, “Royalties received and accrued...”	16	
Future Royalty Streams Identified for Sale			
27	The field test team stated that key subject matter experts have indicated that this scenario is very highly unlikely. Because such extensive analysis and work was required to satisfy other aspects of the field study, the team did not test this area, noting that there is no	22	No change to the draft ED requirements proposed. The proposed requirement in the ED would require disclosure in the event that this

#	ED View Field Test Team Comments / Methodology	ED FT pg.	Recommended Response
	disagreement with the proposed disclosure and accounting treatment; however, if the alternative valuation method is selected, then valuation based upon the known quantities would be developed using that method.		scenario does arise (see pars. 33 – 36). If the scenario never occurs, there would be nothing to disclose.
Revaluation			
28	The team noted that several factors had to be included in deriving the averages, such as estimating the value of commodity received in kind and delivered to DOE to fill the Strategic Petroleum Reserve (SPR).	25	Eliminate detailed guidance on how to calculate asset value; allow for flexibility.
Other Comments			
29	The ED currently only addresses the accounting treatment for oil and gas, and not other commodities. This means that there would be different accounting treatment and models required for oil and gas compared to solids and other commodities, as well as other activity currently classified as custodial. MMS strongly recommends that implementation be delayed until all commodities and related business activities are addressed.	33	Comment noted; however, a strong majority of the board voted to continue issuing an ED on oil and gas only. Discussion will be added to the BfC to explain the board's rationale.
30	The Standard does not address the treatment of interest, either payable or receivable, whether related to oil and gas, or otherwise. However, it does rescind the provisions in existing Standards that provide for custodial accounting for royalty activity. This is significant, because currently interest related to royalty payments is treated as custodial. Clarification is needed to ascertain the Board's intent regarding other such business activities. Nonetheless, system changes will ensue for differing accounting models related to these types of related financial events.	33	Add clarification to the ED regarding reporting for other royalty activity besides oil and gas.
31	System issues pose significant implementation challenges to MMS/MRM.	33 – 35	Comment was included as part of the board's overall cost/benefit considerations.
32	Cost estimates of system changes, assuming simplistic changes to SGL accounts only, range from \$5M if done for all commodities at once, to \$7M if other commodities are implemented later.	35	Comment was included as part of the board's overall cost/benefit considerations.
33	The decreases due to intermediate production and the increases due to new proved reserves additions that occur between the effective date of the reserve estimates and the effective date of the booked asset value represent true and measurable variations in the final proved reserves estimate that must be factored into the final asset value. The MMS proposes incorporating a factor for this variation in the final estimated quantity, such as has been developed by the MMS OMM subject matter experts and described in the OMM alternative view field test response.	36	No change to the draft ED requirements proposed. The field test team's methodology regarding intermediate production introduces additional high-level estimates that are deemed unnecessarily complex in arriving at an estimated asset value.

#	ED View Field Test Team Comments / Methodology	ED FT pg.	Recommended Response
34	The FASAB Exposure Draft view proposes to base values on, "...the most recent survey conducted by the EIA, issued no more than twelve (12) months before the end of the reporting period..." However, if the first such estimated value were to be booked at the start of fiscal year 2009 (October 1, 2008), the EIA reserve estimates available to calculate the value would be effective on December 31, 2006. This is a full 21 months prior to the effective date of the estimate of value. Accordingly, we recommend the ED be worded to base valuation simply on the most recent survey available from EIA.	37	Eliminate detailed guidance on how to calculate asset value, including specific source of information; allow for flexibility.
35	Obtaining, classifying and stratifying the royalty reported data is a time-consuming effort that will require refinement and if the ED view is implemented, will be laborious to complete and subject to a high degree of audit review. Adequate numbers of knowledgeable staff will be crucial and careful reviews and quality control will be key to success, because the slightest error could have material repercussions, and could impact all downstream recipients as well.	37	Comment was included as part of the board's overall cost/benefit considerations.
36	When the annual calculations are performed, the timing of available reported royalty data is such that a 2-month lag may exist from the month of production (the sales month) to the month of required royalty reporting. Accordingly, the text in the ED should provide for this by inserting "...that royalty data for corresponding production (sales) months is available..."	37	Eliminate detailed guidance on how to calculate asset value, including specific source of information; allow for flexibility.
37	We recommend that if using the ED view, the Statement and Appendices clarify that the major commodity categories in common between EIA and MMS be disaggregated, the averages computed separately, and then summed to derive the asset value. Please refer to the discussion in entry #1 above.	38	Eliminate detailed guidance on how to calculate asset value, including component calculations; allow for flexibility.
38	Settlement payments are generally matched to a royalty report that does not break out what portion may possibly be estimated to be related to commodity royalties, or interest, or civil penalties; internal process would need to be changed to capture more detail.	38	Comment was included as part of the board's overall cost/benefit considerations.
39	Periodically, MMS receives royalty related payments against invoices that are reported generically as custodial 'Rents and Royalties'. The invoice does not provide for a product code or other detail related to the nature of the obligation, but simply contains an amount due with no product code, so can not be broken out further; internal system process would need to be changed to capture more detail.	38 - 39	Comment was included as part of the board's overall cost/benefit considerations.
40	New Standard General Ledger (SGL) accounts, reciprocal pairs and posting models will need to be developed, approved, and incorporated into Treasury financial statement crosswalks.	40	Comment was included as part of the board's overall cost/benefit considerations.
41	Reporting exception required to use clearing account F3875.	40	Comment was included as part of the board's overall cost/benefit considerations.
42	MMS/MRM records as revenue in the current period, both positive and negative amounts resulting from adjustments to prior royalty reporting, for sales (production) months other than	41	Par. 21 from the May 2007 ED has been moved to a footnote reference in the current draft ED

#	ED View Field Test Team Comments / Methodology	ED FT pg.	Recommended Response
	just the current months. The volume of these adjustments to prior period royalty reporting is significant, recurring, and may span multiple years. This practice is foundational to royalty reporting. We request that the Board consider clarifying related provisions in the ED accordingly.		(see footnote 9). Furthermore, the language in the ED is clear that “an amount equal to the royalty revenue [including adjustments to prior royalty reporting] shall be recognized as depletion expense on the statement of net cost of the component entity that is responsible for collecting the royalty revenue.” A methodology can be developed to estimate the portion of unmatched cash, adjustments, and accruals to be allocated to oil and gas. No further changes to the draft ED requirements proposed.
43	The Statement does not address all commodities accounted for by MMS/MRM, such as solid minerals (and related interest). We are presuming that all commodities not covered under the ED would continue to be treated as custodial, according to established provisions in SFFAS 7, pp. 45, 275, 276, and 277. We request that the Statement clearly provide for these commodities, and allow current practices related to them to continue as custodial under existing guidance in SFFAS 7.	41	Add clarification to the ED regarding reporting for other commodities besides oil and gas.
44	The Statement does not address interest derived from royalty related activity, currently also treated as custodial. The interest component bears no relationship to depletion of the asset, but if related to oil or gas, guidance is needed regarding accounting treatment, to determine if it should still be treated as custodial or on the SNC.	41	Add clarification to the ED regarding reporting for other royalty activity besides oil and gas.
45	The Exposure Draft and accompanying Appendix C do not break out or distinguish between long or short-term liabilities, nor does the pro forma balance sheet present them separately, in relation to the nature of the offsetting assets. We request this be discussed in the Standard and associated Appendices.	41 - 42	Add clarification to the ED regarding the classification of liabilities. See Issue Paper No. 3 at Appendix 1.
46	Currently, EIA does not publish numbers related to proved reserves on Indian lands. Further, MMS only receives a small portion of royalties related to Indian leases, which are distributed to OST for subsequent funds management and distribution to Tribes. Accordingly, there is presently not a means for MMS to know how to estimate an asset value, nor how to present estimated depletion. While estimates could always be developed, the validity of the data could later be proved to be incorrect, and would be a very broad estimate at best.	42 - 43	[Awaiting DOI’s response to Issue Paper No. 2 before staff can form a recommendation.]
47	BLM receives some royalty amounts that are transmitted 2 or 3 times per month to MMS/MRM, where they are then matched to the lease and distributed according to lease terms. The BLM receipts and distributions to MMS are captured as custodial activity and reported on the Statement of Custodial Activity (SCA). For purposes of the Statement, we do not currently think this would pose a problem, as MMS would still be the ‘collecting entity’ who bears the responsibility for reporting on the satisfaction of the lease obligation and would	43	Comment noted; no changes to the draft ED requirements proposed.

#	ED View Field Test Team Comments / Methodology	ED FT pg.	Recommended Response
	record the depletion expense. BLM also receives 'Rights of Way' payments on leases for which the Bureau of Reclamation, the General Fund of the Treasury and States are designated recipients. These payments do not relate to commodity depletion, nor do they flow through MMS at any time. They are also recorded on the SCA. At this time, it does not appear that the Statement would impact this activity, or result in the elimination of the BLM SCA. However, we ask that the Board consider this when finalizing the Statement.		
48	Earned revenue includes numerous components including estimates, which cannot be readily broken out into categories such as onshore vs. offshore, etc. We request that the Statement clarify the disclosure requirement, such that the disclosure relate specifically to the royalty data linked with depletion expense, and indicate that it is not all-inclusive of total revenue recorded in the financial statements for the period.	43	No changes to the draft ED requirements proposed. The disclosure should be all-inclusive of total royalty revenue recorded in the financial statements for the period. See recommended response to numbers 16 – 25 above and Issue Paper No. 4 at Appendix 1.
49	The information required to be provided in the ED is not available, and so could not be provided by the MMS. This is information that can only be gathered and provided by the EIA. As discussed in the valuation process above, MMS had to obtain EIA nationwide data and develop a rough estimation methodology to attempt to arrive at an estimate of the estimated proved reserves under federal domain. The additional information required in the ED for RSI disclosure, such as federal domain technically recoverable resources, onshore and offshore, and historical 10-year information on federal domain estimated proved reserves could only be provided by EIA. If the Board intends that estimated calculations be produced, we request that be clarified. However, such things as net revisions, extensions, new field discoveries, etc. could not be reasonably ascertained.	43	Delete the RSI requirements from paragraphs 32a and 32c in the May 2007 ED. Require a reference to source reports used to calculate the value of the federal government's estimated petroleum royalties to alert the reader where to go for more information on nationwide data. See Issue Paper No. 1 at Appendix 1 for further discussion of the RSI disclosures.

Recommended Response to PV View Field Test Team Comments / Methodology

#	PV View Field Test Team Comments / Methodology	PV FT pg.	Recommended Response
50	To compute the illustrative revaluation of estimated petroleum royalties at fiscal year end, MMS CRB simply computed the percentage decline in asset value obtained in the ED view calculations, and applied that same percentage decline to the offshore and onshore beginning balance PV method values, to arrive at the end of period PV method balance. There is no direct relationship between the methods or time frames, and this was done simply to provide a hypothetical end of period value. It is interesting to note that although the overall asset value declined (hypothetically), depletion recorded in the year exceeded the straight difference in the valuation, and required a gain on revaluation to be recorded. This gain may not be reflected in subsequently published EIA data.	19 - 20	Comment noted; no changes to the draft ED requirements proposed.
Proved Reserves Estimates			
51	Ideally, such estimates of proved reserves would need to be divided according to commodity (crude oil, lease condensate, and natural gas – wet after lease separation), and, in the Gulf of Mexico (GOM), further for each commodity by the water depth category of the field.	28 - 29	Eliminate detailed guidance on how to calculate asset value, including component calculations; allow for flexibility.
52	In reality, the DOI has had difficulty communicating with the EIA to determine if they can comply with the proved reserves data needs expressed above. The MMS/OMM strongly recommends that an agreement be reached with the DOE/EIA to provide the necessary proved reserves data in the appropriate form and format for this or any method adopted for the reserves valuation. Alternatively, the MMS has devised a means for estimating the proportions of EIA proved reserves for the GOM applicable to royalty rates of one-sixth and one-eighth. This has been accomplished by applying the water depth proportions from the most recent MMS proved reserves estimates to the published proved reserve estimates from EIA.	29	Comment noted; FASAB does not have the ability to require DOI/EIA to provide the necessary proved reserves data in the appropriate form and format. That is one of the primary reasons the board decided to eliminate the detailed guidance on how to calculate the asset value, including the specific source of information, and allow for flexibility.
Production Profiles			
53	In order to effectively calculate the present value of Federal royalties, it needs to be estimated how those royalties will be received over time. To determine this, one needs to project how the proved reserves estimates will be produced over time. EIA proved reserve estimates include reserves from which Federal royalties will be received, as well as, reserves from which royalties will not be received due to various royalty relief policies. The model that MMS has created can be used to project the future production of the EIA proved reserve estimates assuming an exponential decline at a rate of the	29	Eliminate detailed guidance on how to calculate asset value; allow for flexibility.

#	PV View Field Test Team Comments / Methodology	PV FT pg.	Recommended Response
	<p>modeler's choice. The model also receives, as inputs, annual estimates of royalty free production from royalty relief. The annual production estimates of the proved reserves calculated by the model are then reduced by the royalty free annual volumes prior to the royalty calculations.</p>		
Natural Gas Plant Liquids			
54	<p>The Exposure Draft calls for the estimation of royalties from proved reserves of natural gas plant liquids (NGPL) along with royalties from proved reserve estimates of crude oil, lease condensate, and presumably dry natural gas. The EIA reports estimates of natural gas reserves in two different forms. One form is Dry Natural Gas which is the volume of natural gas after the natural gas liquids have been removed. The other form is Natural Gas, Wet After Lease Separation which is the volume of natural gas prior to the natural gas liquids being removed. Should dry gas proved reserves be used for the royalty estimates, NGPL proved reserve estimates should also be used to capture the entire hydrocarbon value. However, wet gas volumes and values are greater than dry gas volumes and values because of the additional content of NGPL in the wet gas. MMS prefers the use of the wet gas estimates because they replicate the form and the point in time when the royalty valuations are made. Further, MMS/OMM reservoir engineers and geoscientists are very experienced in dealing with and estimating reserves and production in terms of wet gas as all MMS/OMM datasets are in terms of wet gas. Finally, the use of dry gas and NGPL creates possibly insurmountable problems in properly allocating reserves back to their source fields, affecting value estimations at the proper royalty rates, and in constructing production profiles. Adding values for NGPL to this would amount to a double counting of the values of NGPL. MMS has used only wet gas proved reserves estimates (and no estimate of NGPL) in its trial analysis and highly recommends this procedure for these calculations.</p>	29	Eliminate detailed guidance on how to calculate asset value, including component calculations; allow for flexibility.
Product Prices			
55	<p>Of equal importance in the estimation of the present value of royalties to the production estimates are the estimates of future oil and gas prices. MMS-OMM recommends that independently generated and commonly available price estimates be used. The MMS-OMM already uses and is familiar with the OMB economic assumptions that are generated semi-annually for the President's Budget. For the purpose of the trial analysis performed, the oil and gas prices from the OMB's "Economic Assumptions for the 2008 Mid-Session Review" were employed. A minor limitation to those parameters is that the projections are only for 10 years into the future. An extrapolation of out-year trends in the projections has been made to extend the price profiles as long as necessary.</p>	30	Eliminate detailed guidance on how to calculate asset value; allow for flexibility.

#	PV View Field Test Team Comments / Methodology	PV FT pg.	Recommended Response
	<p>Depending on the locations associated with the price parameters, the prices will have to be adjusted to approximate average wellhead prices for each OCS Region (GOM, Pacific, Alaska North Slope). Such an adjustment has two components, an adjustment to a regional landed average price, then a transportation allowance to a regional wellhead average price. The first adjustment to a regional landed average price will be conducted by observing the historical average relationship of the price series being considered (e.g., United States average wellhead natural gas price) to the average regional landed natural gas price (e.g., Henry Hub). From these observations, factors and/or trends in these price relationships can be deduced and applied to the price projections to result in projections of regional landed prices. Such relationships need to be studied in detail prior to “going live” with the present value estimates. For the purpose of the trial analysis performed, it was assumed that the OMB’s average imported and domestic refiner’s acquisition cost for oil and the average wellhead price for imported, inter-, and intra-State natural gas estimates would be equivalent to the average landed prices of oil and gas for each Region. The OMB’s price projections are expressed in nominal terms.</p>		
Transportation Allowances			
56	<p>The second component of the price adjustment is the transportation allowances. Lessees pay royalties based on the value of their production at the wellhead. Since the price adjustment above resulted in a regional average landed price, these need to be converted to regional average wellhead prices by subtracting a regional average transportation allowance. One approach would be for MMS-MRM to determine the necessary average historical transportation allowances claimed by lessees on royalty bearing production for the previous 12 sales months. Such averages would be weighted by the volume of production using that allowance, would be by commodity, and for the GOM, would be by the royalty rate of the contributing leases. The assumption would then be that the resulting previous 12-month average transportation allowances would also apply to all future production within the same category. Because the price projections used are nominal values, the transportation allowances would be increased in the future with inflation. This method was employed in the trial analysis, though further study of the accuracy of this approach would be necessary prior to any official calculations.</p>	31	Eliminate detailed guidance on how to calculate asset value; allow for flexibility.
Discount and Inflation Rates			
57	<p>As for product prices, MMS-OMM recommends that independently generated and commonly available discount and inflation rates be used in calculating the royalty present</p>	31	Refer to SFFAS 33 for the selection of discount rates. For other components of the calculation,

#	PV View Field Test Team Comments / Methodology	PV FT pg.	Recommended Response
	<p>value. A public sector discount rate for the federal government should be readily available and applicable for this purpose. For the purpose of the trial analysis, MMS assumed a discount rate equal to the federal government's interest rate paid on its long-term borrowing as the discount rate. OMB's projection of the 30-year Treasury Bill rate was used. For inflation, MMS assumed OMB's projection of the GDP Price Index for the trial analysis. As was the case for OMB's oil and gas price projections, projections of these parameters by OMB are also only for 10 years into the future. An extrapolation of out-year trends in the projections has been made to extend the price profiles as long as necessary.</p>		<p>eliminate detailed guidance on how to calculate asset value; allow for flexibility.</p>
Present Value Calculations			
58	<p>For all federal offshore areas, MMS proposes the use of the following method to estimate the present value of future federal royalties from proved reserves:</p> <ol style="list-style-type: none"> 1) By federal OCS Region, project production of DOE-EIA proved oil/condensate and wet natural gas reserves estimates over time until depleted, 2) In GOM, also project separately for one-sixth and one eighth royalty rate leases (use water depth subsets of >400m and <400m as proxy), 3) Where applicable, determine adjustments needed to reflect projected royalty free production from royalty relief leases and modify as appropriate the total projections above, 4) Calculate future regional landed prices from price projection (OMB or other) assigned by FASAB using historical price relationships to make further adjustments, 5) Calculate future wellhead landed prices from regional landed prices using average actual transportation allowances claimed for the previous 12-month period. 6) For production for each Regional commodity by royalty rate, calculate annual royalties as follows: $(\text{Annual Production less adjustments for Annual Royalty Free Production}) * (\text{Annual Regional Landed Price} - \text{Average Transportation Allowance}) * \text{Royalty Rate}$ 7) For a given vector of calculated future annual royalty estimates, determine the present value of the royalty revenue stream assuming the discount rate (OMB 30-year Treasury Bill or other) assigned by FASAB. 	31 - 32	<p>Eliminate detailed guidance on how to calculate asset value; allow for flexibility.</p>
59	<p>Since the federal proved reserves derived from EIA published data were for FY 2005, the amount of production from FY 2006 was subtracted from federal proved reserves before starting additional calculations. Using prior years' production data and estimates on new wells permitted and drilled each year, an estimated yearly production was estimated for each year. The estimates in new permits approved and wells drilled were based on the</p>	34 - 35	<p>Eliminate detailed guidance on how to calculate asset value; allow for flexibility.</p>

#	PV View Field Test Team Comments / Methodology	PV FT pg.	Recommended Response
	<p>following parameters:</p> <ul style="list-style-type: none"> • 5% of APDs processed are Indian • 84% of the federal APDs processed are approved • 85% of the federal Approved APDs are drilled • 90% of the wells drilled are productive • 10% of the productive wells are oil • 90% of the productive wells are gas • 85% of the productive wells begin production in the first year • 10% of the productive wells begin production in the second year • 4% of the productive wells begin production in the third year • 1% of the productive wells begin production in the fourth year • Average oil well produces 7,300 barrels per year or 20 barrels per day • Decrease of 10% per year for oil production • Decrease of 10% per year for gas production • Average gas well produces 80,000 MCF per year or 219 MCF per day • APDs processed in 2008 - 2011 are set at 11,500 and then start a slow decline of 500 APDs per year. <p>Once yearly production estimates were established they were subtracted from the federal proved reserves until the proved reserves were zero. A similar present value method was applied to onshore quantities. A yearly estimated price for oil, natural gas and natural gas liquids was used based on OMB estimates. Since the OMB estimates only went out for ten years, prices were estimated based on the trend of the OMB estimates after that. A royalty rate based on historic data from MMS was used to estimate the royalty rate. The data from MMS on the royalty rate appeared to be constant, so no change in the royalty rate was made for each year. A standard discount rate was used to bring future dollars back to today dollars.</p> <p>The estimated yearly production was multiplied by estimated average yearly price, the royalty rate and the discount rate for that year. All of these totals were added together to come up with the estimated value of each commodity (oil, natural gas and natural gas liquids). These totals were added together to come up with a estimated total value of the federal onshore oil and gas proved reserves.</p>		
Intermediate Production			
60	The intermediate production that occurs between the effective date of the reserve estimates and the effective date of the booked value represents a true and measurable reduction in the proved reserves estimate for which the royalty value will have been	36 - 38	No change to the draft ED requirements proposed. The field test team's methodology regarding intermediate production introduces

#	PV View Field Test Team Comments / Methodology	PV FT pg.	Recommended Response																								
	<p>received and accounted for elsewhere. Booking the value of this production as proved reserves would amount to an overstatement of this asset. The MMS proposes reducing the proved reserves by the volume of the intermediate production. At the time for calculating the book value of the proved reserves for FASAB, the MMS will have production volume estimates for approximately 18 of the 21 months of intermediate production and proposes to use production projections for the remaining months.</p> <p>MMS believes it would be inconsistent to reduce the value of the royalty stream by the value of the intermediate production without also including a corresponding increase from proved reserves that would be almost certainly added between the effective date of the proved reserve estimates and the effective date of the booked value. Unlike the intermediate production, however, which can be mostly measured, intermediate increases of the EIA proved reserve estimates are not available for these calculations. The MMS proposes that estimates of the reserves additions be employed and offers the following methodology for estimating revised reserves estimates that are based on the EIA estimates but are effective the date of the booked asset value.</p> <p>The methodology employs the historical relationship between the volume of production of proved reserves and the volume of reserves additions to proved reserves. The EIA has estimated and reported the proved reserves of the Federal OCS areas for many years. In its annual presentation of its reserves estimates, EIA reports the previous year's reserve estimate, all additions to that previous year's estimate, and all reductions to that previous year's estimate (including production). The following are EIA data that track the reserves estimate and corresponding revision categories for crude oil proved reserves of the Pacific Federal OCS for 2005.</p> <table data-bbox="279 1045 1186 1409"> <tr> <td>Proved Reserves as of 12/31/2004</td> <td>547 MMbbl</td> </tr> <tr> <td>Changes in Reserves During Year</td> <td></td> </tr> <tr> <td> Adjustments (+,-)</td> <td>-1 MMbbl</td> </tr> <tr> <td> Revision Increases (+)</td> <td>3 MMbbl</td> </tr> <tr> <td> Revision Decreases (-)</td> <td>81 MMbbl</td> </tr> <tr> <td> Sales (-)</td> <td>0 MMbbl</td> </tr> <tr> <td> Acquisitions (+)</td> <td>0 MMbbl</td> </tr> <tr> <td> Extensions (+)</td> <td>0 MMbbl</td> </tr> <tr> <td> New Field Discoveries (+)</td> <td>0 MMbbl</td> </tr> <tr> <td> New Reservoir Discoveries in Old Fields (+)</td> <td>0 MMbbl</td> </tr> <tr> <td> Estimated Production (-)</td> <td>27 MMbbl</td> </tr> <tr> <td>Proved Reserves as of 12/31/2005</td> <td>441 MMbbl</td> </tr> </table>	Proved Reserves as of 12/31/2004	547 MMbbl	Changes in Reserves During Year		Adjustments (+,-)	-1 MMbbl	Revision Increases (+)	3 MMbbl	Revision Decreases (-)	81 MMbbl	Sales (-)	0 MMbbl	Acquisitions (+)	0 MMbbl	Extensions (+)	0 MMbbl	New Field Discoveries (+)	0 MMbbl	New Reservoir Discoveries in Old Fields (+)	0 MMbbl	Estimated Production (-)	27 MMbbl	Proved Reserves as of 12/31/2005	441 MMbbl		<p>additional high-level estimates that are deemed unnecessarily complex in arriving at an estimated asset value.</p>
Proved Reserves as of 12/31/2004	547 MMbbl																										
Changes in Reserves During Year																											
Adjustments (+,-)	-1 MMbbl																										
Revision Increases (+)	3 MMbbl																										
Revision Decreases (-)	81 MMbbl																										
Sales (-)	0 MMbbl																										
Acquisitions (+)	0 MMbbl																										
Extensions (+)	0 MMbbl																										
New Field Discoveries (+)	0 MMbbl																										
New Reservoir Discoveries in Old Fields (+)	0 MMbbl																										
Estimated Production (-)	27 MMbbl																										
Proved Reserves as of 12/31/2005	441 MMbbl																										

#	PV View Field Test Team Comments / Methodology	PV FT pg.	Recommended Response
	<p>Since the MMS will have a reliable estimate of the intermediate production, a method was devised to determine the EIA historical average proved reserves change expressed in proportion to historical average production of proved reserves. For example, between 1992 and 2005, EIA's proved oil and lease condensate reserve estimates for the deep water Gulf of Mexico increased by 2.771 billion barrels. Correspondingly, over that same 14-year period, EIA reports that 2.833 billion barrels of oil and lease condensate were produced from the same area. This indicates over that time period, for every barrel of production that occurred, the oil reserves estimate increased by 97.81% of a barrel ($2.771/2.833 = 0.9781$).</p> <p>Potentially, this concept can be confusing because of the varying terminology used in the above description. It is important to realize that the reserves estimate adjustment methodology suggested above accounts for reserves additions as well as reserves reductions, including production. This is because the reserves estimate adjustment factor proposed is the determination of the change in the reserves estimate expressed in proportion to the volume of production over the same time period. The important concept to remember is that the volume of production is also a component of the change in reserves estimate.</p> <p>Using these calculated averages for each appropriate area, and the volumes of intermediate production, MMS proposes that the EIA proved reserves estimates, effective 21 months prior to the effective date of the booked value, be adjusted to a value that is reflective of the effective date of the booked asset value. Continuing with the same example of Gulf of Mexico deep water proved reserves of oil and lease condensate, the proved reserve estimate was 3.626 billion barrels as of December 31, 2005. The MMS estimates 592 million barrels of intermediate deep water GOM oil and lease condensate production over the 21 months between December 31, 2005 and October 1, 2007. Applying the average reserves change to production ratio, the December 31, 2005 GOM oil and lease condensate proved reserve estimate of 3.626 billion barrels would increase by 579 million barrels (592 million barrels produced * 97.81% = 579 million barrels reserves change) to 4.205 billion barrels by October 1, 2008. These data along with the similar data elements for the other Federal OCS areas are shown in the table below.</p>		

#	PV View Field Test Team Comments / Methodology						PV FT pg.	Recommended Response
	GOM 1/6 th Royalty Oil (MMbbl)	GOM 1/8 th Royalty Oil (MMbbl)	GOM 1/6 th Royalty Gas (Bcf)	GOM 1/8 th Royalty Gas (Bcf)	Pacific Oil (MMbbl)	Pacific Gas (Bcf)		
Proved Reserves on 12/31/05	688	3,626	10,014	7,412	449	825		
Production 1/1/06 – 9/30/07	221	592	2,958	1,914	43	80		
Average Reserves Change to Production Ratio	-22.16%	97.81%	- 29.66%	40.95%	-70.32%	-111.56%		
Proved Reserves on 9/30/07	639	4,205	9,136	8,196	419	736		
<p>The MMS/OMM acknowledges improvements over this method include the receipt of EIA's proved reserves estimates sooner. That is, receiving estimates that are only 9 months out of date, instead of 21 months. This would involve the receipt of the necessary estimated prior to EIA publishing the values. Another improvement is if EIA could provide all of the above data in exactly the form and format needed which would mean by water depth category in the Federal offshore Gulf of Mexico, and perhaps for Federal only proved reserves for the Federal onshore.</p> <p>This adjustment factor is included in the offshore calculations. A production decline factor is included in the onshore calculations, but no factor was included for potential increases or additions. This highlights a significant issue requiring resolution before implementing any valuation methodology, regardless of the valuation method selected.</p>								

Tab F-4
**Appendix 3 – History of
Project and Key Decisions**

[This page intentionally left blank.]

Natural Resources

History of Project and Key Decisions

May 1995 - Present

July 1995 - Staff presented first issue paper; Board requested more background information, including a review of relevant FASB standards.

November 1995 - SFFAS 6, *Accounting for Property, Plant, and Equipment* issued; only addressed surface land area, excludes natural resources due to complex issues involved.

April 1996 - The Board determined that stocks of game, fisheries, and wildlife habitat would be excluded from the scope of the standard. Also, Board decided it is only interested in reporting information about natural resources contained on federal lands. Staff was directed to prepare a hierarchy of disclosure standards for all traditional natural resources, excluding timber. Staff was directed to prepare separate requirements for timber.

May 1996 (contd.) - Staff presented the Board with possible reporting requirements for a natural resources standard and proposed four categories of natural resources: (1) natural resources extracted, produced, and sold by a federal entity; (2) quantifiable lease program natural resources; (3) non-quantifiable lease program natural resources; and (4) timber. Concerned with relevance and reliability, the Board decided to create a task force to study the kinds of natural resources information currently available and to provide options for framing relevant information to be reported in federal financial reports.

January 1997 - Natural resources task force held its first meeting. The task force was made up of accountants, economists, geologists, and program experts from various federal entities and the private sector.

October 1997 - Mr. Leshner presented the Board with an update of the task force activities since January 1997, including natural resources addressed and the current view of natural resource "stages" (stocks and flows): conveyed/sold; available for sale; not available for sale; and unknown/undiscovered resources. The specific natural resources addressed within the scope of the project are: timber; outer continental shelf oil and gas resources; leasable minerals (e.g., oil, gas, coal, oil shale, geothermal resources, gilsonite, phosphate, potassium, potash, sodium); locatable minerals (e.g., gold, silver, nickel); mineral materials (e.g., sand, stone, gravel, pumice, and other volcanic stone, clay and rock); grazing rights; electromagnetic spectrum; and water rights. Mr. Leshner said the task force expected to have preliminary recommendations by December.

May 1995 - Natural resources identified as a high priority project. Former executive director (Ron Young) announced that staff would begin developing an issue paper.

September 1995 - Staff provided Board members with an informational paper on FASB SFAS 19, 25, 69 and 89.

January 1996 - Staff provided Board members with a paper that listed federal agencies and their responsibilities for natural resources; an updated set of issues; and, the type of information on natural resources currently available.

May 1996 - SFFAS 7, *Accounting for Revenue and Other Financing Sources* issued; excluded royalty revenue from SoNC even though exchange because there is no offsetting depletion expense. This remains an exception to the recognition of exchange revenue on the SoNC (along with the auction of the radio spectrum).

June 1996 - SFFAS 8, *Supplementary Stewardship Reporting*, issued; only addressed surface land area, excluded natural resources from stewardship reporting due to complex issues involved.

September 1996 - Board approved formation of natural resources task force and related "Charge to Task Force" memorandum, noting that reporting a source of the country's wealth and its potential wealth for the future was important. Schuyler Leshner appointed as chair of task force. Executive Director Ron Young retired September 30, 1996.

April 1997 - The task force chair presented revised scope of task force charge, stating that the project would include those extractable natural resources owned by the federal government or under federal stewardship and the electromagnetic spectrum, where a commercial market exists for the resource. This includes economic mineral resources (e.g., oil, gas, coal, gold, silver, sand, clay, gravel, etc) and the following renewable resources: timber, forage, and water for which the federal government owns the rights.

January 1998 - The task force chair presented a preliminary draft of a natural resources fact-finding paper. While the outline of the paper identified nine major sections, the paper addressed only three of the sections. Mr. Leshner said the task force expected to complete work on the remaining sections of the fact-finding paper in about 6 weeks.

Natural Resources

History of Project and Key Decisions

May 1995 - Present

April 1998 - Task force presented a revised paper that included a discussion on the general reporting principles, including asset reporting, accounting and reporting for revenue, and accounting and reporting for costs. The revised paper also contained a section on the impact of the proposed changes on current FASAB standards and a discussion on Indian natural resource assets held by the federal government in trust for Indian tribes and individuals.

March 1999 - Natural Resources Task Force Draft Report issued from Mr. Leshner to the CFO Council and PCIE Members for comment. Comments were requested by May 3, 1999.

December 2000 - The Board voted to eliminate the category RSSI - required supplementary stewardship information.

[Project deferred to address other issues]

October 2002 - After reviewing and discussing a revised project plan presented by staff, the Board approves work to commence on the current natural resources project.

February 2003 - Staff presented a revised project plan that included the integration of possible revisions to the current FASAB reporting objectives. The Board directed staff to begin developing an ED with a BfC.

June 2003 - The Board asked staff to look at how the proposed recognition of oil and gas resource collections and disbursements would affect an entity's Statement of Custodial Activities and prepare pro forma disclosures that could be included in entity financial reports. Staff was also asked to research the pros and cons for capitalizing oil and gas assessments (an assessment is an estimate of undiscovered oil and gas resources on the basis of geologic knowledge and theory to exist outside of known accumulations).

December 2003 - Staff informed the Board that MMS does not track assessment costs separately from other resource evaluation (RE) costs. In addition, total RE costs are immaterial in comparison to annual bonus bid, rent, and royalty collections. Staff sought approval of proposed oil and gas disclosures with no asset recognition due to the various uncertainties involved in measur-

October 1998 - FASAB staff continued to work with the task force to issue a final task force report. Several more meetings were held to discuss open issues such as whether natural resource exchange revenue that is collected without incurring matching costs should be reported in the Statement of Net Cost or as custodial revenue.

June 2000 - FASAB issues Discussion Paper "*Accounting for the Natural Resources of the Federal Government*" prepared by the FASAB Natural Resources Task Force. The report recommended stewardship reporting as the primary mechanism for reporting information on natural resources. Although the task force believed that the value of natural resources available for sale was important, it concluded that the balance sheet was not the most reliable or effective way to accomplish such reporting due to uncertainty over quantity and market price. Minority comments included in Appendix B of the report state that "resources used for remunerative purposes should be reported on the balance sheet and Statement of Net Cost." The full report is available at <http://www.fasab.gov/pdffiles/natresrpt.pdf>

December 2002 - Staff presented a revised project plan based on prior Board discussions. Staff also provided summarized comments received from several members since the October meeting, noting that these comments leaned toward recognition of natural resources as an asset. The Board agreed that staff would develop standards for oil and gas first and then apply the framework to other types of natural resources.

April 2003 - Staff provided a draft skeletal exposure draft and concluded that, although oil and gas meet FASAB's working definition of "asset," the resources do not meet the recognition criteria because they cannot be reliably measured. The board asked staff to continue their research on current reporting practices as well as options for measuring the oil and gas resources and come back to the Board for discussion.

October 2003 - Staff presented revised proposed disclosure requirements for Board review. The Board directed staff to remove disclosure requirements for total number of leases and non-producing leases and reasons leases are non-producing, concluding that the information was not useful. Staff was also asked to obtain assessment cost information from MMS and provide it to the Board.

Natural Resources

History of Project and Key Decisions

May 1995 - Present

ability. The Board directed staff to pursue capitalization of the anticipated production stage revenue stream, which included researching accounting literature that deals with long-term contracting and leasing in relation to measurement and recognition criteria. This was the Board direction even though staff had initially concluded that quantities from expected oil and gas production were not estimable, due to the unpredictability of the economy, business decisions by the producers, and the advancement, or lack of it, in technology.

July 2004 - Staff presented a proposed valuation methodology and financial statement disclosures using current market value. The Board requested an expanded discussion on alternative measurement attributes. In addition, the Board requested that guidance be sought from the auditors to identify any potential barriers to auditing proved reserves.

December 2004 - Staff presented a revised BfC that included a discussion on many of the questions raised by members at the August 2004 meeting. Members requested additional research and explanation in a number of areas, including a detailed description of "average wellhead price," reliability of EIA proved oil and gas reserve quantities, accounting entries, disclosures, pros and cons of using the discounted cash flow methodology, average time over which oil and gas is extracted from a producing well, and whether bonus bids are proportionate to the value of the federal government's royalty share.

March 2005 - Staff presented another revised BfC to the Board members in which staff had proposed using the national average wellhead price. The Board asked staff to research whether it would be better to use the average wellhead price for each field. The Board also asked staff to perform more research on whether the amount should be discounted. All members, excepts Messrs. Reid and Farrell agreed that information on undiscovered resources should be reported as RSI. Board members decided that the term "estimated Federal royalty share" should be changed to "estimated petroleum royalties."

October 2005 - Staff provided a paper that described the valuation of the federal asset "estimated petroleum royalties" that was based on national average prices and royalty rates. The Board agreed with the staff proposed formulas except Mr. Torregrosa indicated that regional average prices and royalty rates should be used, especially for future revenue streams that had been identified for sale. Board members agreed that a requirement should be added in the standards to address royalty streams identified for sale.

March 2004 - Staff explained that previously, the EIA did not distinguish between the quantity of proved reserves from lands under federal jurisdiction and the quantity of proved reserves from other lands. However, the EIA was then tasked with the requirement to provide this information in its September 2004 reports. Therefore, because this information would be available, staff proposed that an estimated value for proved oil and gas reserves from lands under federal jurisdiction might be capitalized. The Board received information on measurability of proved reserves from MMS and EIA experts via a conference call. The Board agreed that staff should explore the possibility of capitalizing a value for proved oil and gas reserves and consider disclosing information about other classifications of oil and gas resources.

August 2004 - Staff presented a draft ED that proposed using current market value. The ED explained that net present value was eliminated from consideration as a measurement attribute because the period of time over which the money could be earned is not determinable, thereby inhibiting selection of an appropriate discount rate. The Board decided to use the average wellhead price to value cash inflows from oil and gas resources instead of current market value because the wellhead price is what the royalty payment is based on. The wellhead price, which is calculated by EIA, is the value for oil and gas at the mouth of the well and is considered to be the sales price to the initial purchaser without the addition of any other costs, such as transportation and insurance. The Board also decided to change the title of the proposed standards from "Reporting Requirements for Federal Oil and Gas Resources" to "Accounting for Federal Oil and Gas Resources." Staff provided members with a copy of the "Society of Petroleum Engineers (SPE) Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserve Information."

August 2005 - Staff provided EIA and DOI responses to a number of open questions from the March meeting. In addition, a representative from EIA and a representative from DOI attended the meeting and responded to various member questions. The representatives recommended that the calculation for valuing the estimated petroleum royalties be straightforward and manageable. Staff was directed to continue developing the ED.

January 2006 - Staff presented a draft ED that included estimated quantity, price, and royalty rate information on a regional basis rather than at a national level. This was deemed to provide a more representative valuation. Staff also addressed future royalty rights held for sale in the revised ED. The Board

Natural Resources

History of Project and Key Decisions

May 1995 - Present

March 2006 - The Board reviewed a revised draft ED and provided comments, including requesting that staff draft several questions for respondents that cover the level of information requested to be disclosed in the footnotes or displayed as RSI; the challenges posed by the use of the present value measurement attribute for measuring estimated petroleum royalties; and the use of reserves classified as proved, probable, and possible to calculate the value of the federal government's estimated petroleum royalties for capitalization on the balance sheet, instead of using only the proved reserves as proposed in the ED. The Board also requested that staff research the royalty relief program and provide additional information at the next meeting.

July 2006 - The Board reviewed a revised draft ED that included an alternative view from CBO that fair value should be used to value the federal government's natural resources instead of the proposed valuation methodology. There were no objections from Board members to include the CBO alternative view in the ED. The Board also decided to calculate the value of natural gas plant liquids (NGPL) separately from oil and lease condensate. This was the result of an issue raised by CBO that the average price per barrel of NGPL was significantly lower than the average price per barrel of oil and lease condensate. Board members also agreed with CBO's recommendation that the dry (processed) gas price would be used in calculating the value of estimated petroleum royalties for gas as opposed to the wet (unprocessed) gas price. This issue was raised because the proposed standards specified that proved reserves of natural gas would be measured as pipeline quality. The dry (processed) gas is the pipeline-quality gas that has had the liquids removed.

March 2007 - Staff presented the Board with a ballot ED; however, several more clarifying changes were requested to be made to the draft, including that a question on cost/benefit considerations be included in the Request for Comments and a more robust discussion about the current and proposed asset and liability definitions be added. The Board asked staff to make the changes discussed and circulate another pre-ballot draft.

September 2007 - Since the Board received a request for the comment period to be extended and only one comment letter had been received, the Board agreed to extend the comment period until January 11, 2008. Staff was asked to make a concerted effort to reach out to groups and experts to respond.

provided a number of comments on the revised ED, including a request that pro forma accounting transactions, pro forma financial statements, and a discussion of the timing of the transactions be included.

May 2006 - The Board reviewed a revised draft ED and an issue paper on the royalty-free production of oil and gas. Board members agreed that a requirement would be added in the ED to report the annual estimated value for royalty relief as RSI. In addition, they agreed that a question would be added to the request for comments section of the ED pertaining to this requirement. Board members also agreed to staff's recommendation that RSI reporting be required for technically recoverable resources as a whole versus delineating between unproved and undiscovered resources as that information was not readily available. Staff suggested that it begin working on coal for the next phase of the natural resources project. However, the Board directed staff to look at a group of mining materials to try to come up with a standard which has similar principles for a group of mining materials.

November 2006 - The Board asked staff to insert a question addressing the regional disclosure information in the Request for Comments section and to add text in the BfC addressing concerns regarding the proposed disclosures. The Board also tentatively agreed that a liability exists and should be recognized for the estimated petroleum royalties which the government is obligated to distribute to others in accordance with authoritative laws and regulations.

January 2007 - The Board reviewed the revisions to the ED that incorporate the recognition of a liability and clarify the questions for respondents and approved the circulation of a pre-ballot draft prior to the next meeting.

May 2007 - An exposure draft entitled *Accounting for Federal Oil and Gas Resources* was issued for public comment on May 21, 2007. Comments on the proposals presented in the ED were requested by September 21, 2007. The Board requested that the proposal be field tested during the comment period.

February 2008 - Eight comment letters were received through February 4, 2008. Based on the nature of the responses, the Board concluded that a public hearing was not necessary but may elect to follow up on the individual responses as needed. Long-time FASAB project manager Rick Wasca retired.

Natural Resources

History of Project and Key Decisions

May 1995 - Present

June 2008 - The board rejected staff's proposal to develop a comprehensive standard on all natural resources and directed staff to continue with the development of a final standard on oil and gas. Staff will invite DOI to appear before the board to discuss their alternative proposal from the fieldwork testing including why they requested an even lower level of detail than was prescribed in the standard as well as their thoughts on what a less prescriptive standard would mean to them and how it might apply to other resources under their domain. In addition, staff will research the reason the board decided to look at one resource at a time, review current SEC requirements, find out how the private sector currently reports private reserves, obtain revenue numbers on the different types of natural resources, and attempt to make contact with EIA to find out if and when another report on proved reserves under federal lands will be published.

October 2008 - After hearing from the DOI representatives regarding their experience during field testing of the May 2007 ED, the board members directed staff to draft a principles-based ED for their consideration.

December 2008 - The board members unanimously supported continuing efforts to issue an ED. The members directed staff to retain the scope of the ED as oil and gas only, preserve the level of detail in the draft ED, delete the formula in the previously exposed ED (quantity X price X royalty rate), and keep the effective date as drafted (three year phase-in from RSI to basic with a date certain). Staff will incorporate those changes and address additional issues (fiduciary reporting, liability classification, component entity RSI, reporting for other commodities, showing gains and losses on the component entity SoNC, and reporting changes in assumptions) while working towards a pre-ballot revised ED for the April 2009 meeting.